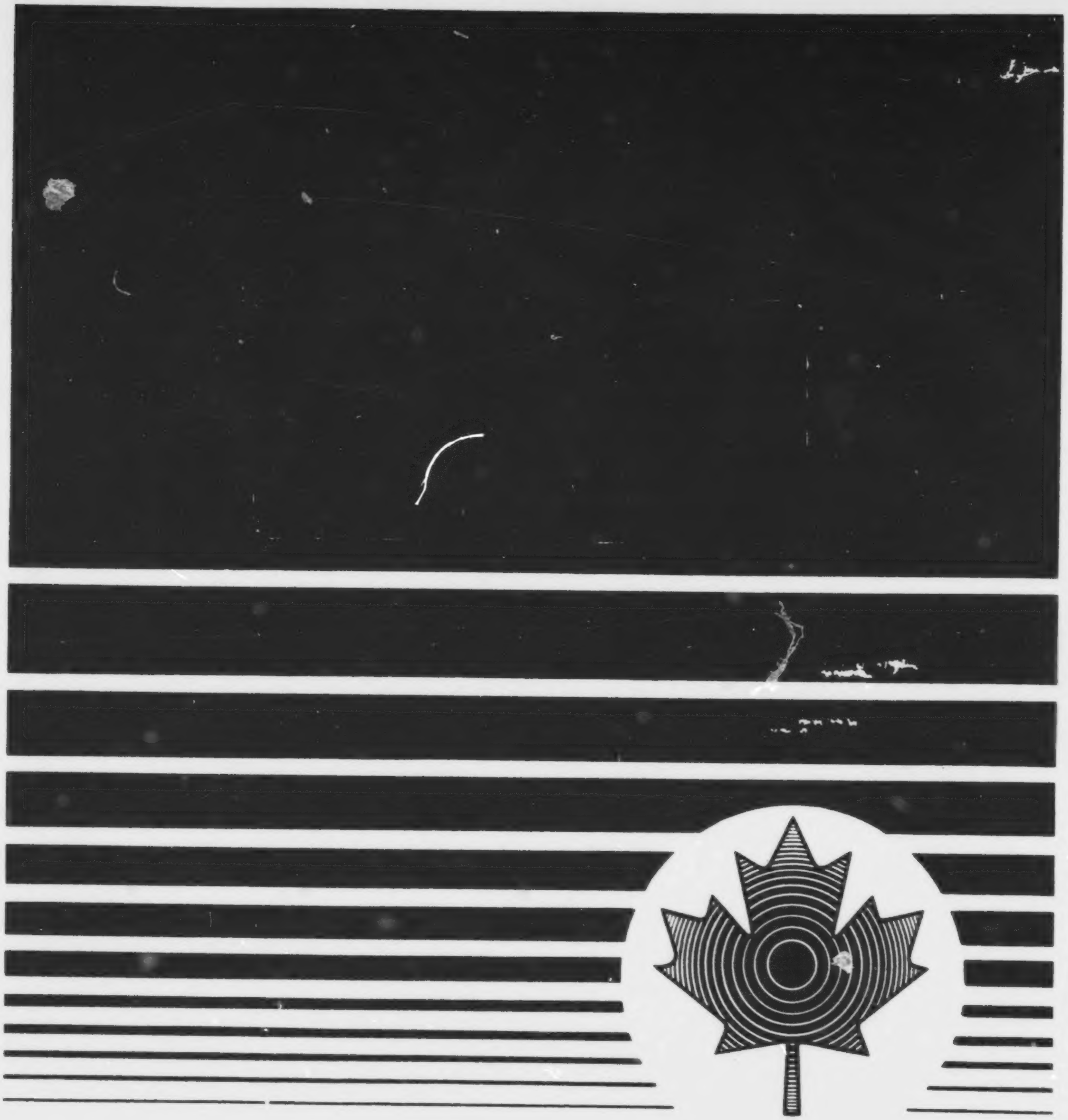

CANADIAN
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PAPERS PRESENTED AT THE
[illegible]TERNATIONAL OIL AND GAS MARKETS CONFERENCE

Calgary, Alberta
September 15-16, 1986

Canadian Energy Research Institute
3512 - 33 Street NW
Calgary, Alberta T2L 2A6
(403) 282-1231

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FINAL PROGRAM

THE INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

Sponsored by
Canadian Energy Research Institute
and
Calgary Chamber of Commerce

September 14-16, 1986

SUNDAY, SEPTEMBER 14

7:00 p.m. - 10:00 p.m.	Registration and Reception, Garden Terrace

MONDAY, SEPTEMBER 15

7:30 a.m.	Registration - Macleod Hall "A"
8:30 a.m. - 8:45 a.m.	Welcome Conference Chairman G. E. Angevine, Executive Director Canadian Energy Research Institute Calgary, Alberta

8:45 a.m. - 10:15 a.m.

"THE WORLD OIL MARKET: I"

Moderator:
Anthony E. Reinsch, Manager, Project Research
Canadian Energy Research Institute
Calgary, Alberta

"Non-OPEC Production Through the Medium Term"

John E. Treat, Executive Publisher
Petroleum Intelligence Weekly
New York

"The World Oil Market: Structural Change from an International Perspective"

Marcel Kramer, Head, Oil Industry Division
International Energy Agency
Paris

"The Outlook for the Price of Oil in the World Market to 1990"

Charles T. Maxwell, Vice Chairman and Senior Energy Strategist
Cyrus J. Lawrence Incorporated
New York

10:15 a.m. - 10:30 a.m. Coffee Reception

10:30 a.m. - 12:00 p.m.

"THE WORLD OIL MARKET: II"

Moderator:
Talaat Abdel-Malek
Director, International Business Division
Center for International Education and Business
University of Calgary
Calgary, Alberta

"OPEC: What Next"

Mohammed Akacem, Senior Economist
Research and Economic Studies Department
Saudi Fund for Development
Riyadh, Saudi Arabia

"Venezuela: Meeting the Challenge of a Fluctuating Market"

Jose M. Prats
Strategic Planning Manager
Trading and Supply Coordination
Petroleos de Venezuela S.A.
Caracas, Venezuela

12:00 p.m. - 2:00 p.m. Luncheon

"MIDDLE EAST POLITICS AND PETROLEUM - IS THERE A LINK?"

Hermann Fr. Eilts, Director, Centre for International Relations
Distinguished University Professor of International Relations
Boston University
Former U.S. Ambassador to Saudi Arabia and Egypt

2:00 p.m. - 3:30 p.m.

"INTERNATIONAL GAS MARKETS"

Moderator:
G. E. Angevine, Executive Director
Canadian Energy Research Institute
Calgary, Alberta

"A Global View of Gas Reserves and Markets"

Richard Itteilag, Director, Gas Demand Analysis
American Gas Association
Arlington, Virginia

"International Gas Trade: The Outlook"

Loren C. Cox, Director of Development and Special Projects
Columbia University
Lamont-Doherty Geological Observatory
Director for Program Development in the U.S.
for Petroleum Economics Limited, U.K.
Palisades, New York

"Gas Developments in Europe"

David J. Wright, Energy Economist
Commission of the European Communities
Directorate-General for Energy
Brussels, Belgium

3:30 p.m. - 3:45 p.m. Coffee Reception

3:45 p.m. - 5:15 p.m.

"PACIFIC RIM OIL AND GAS MARKETS"

Moderator:
Robert G. Welty, Chairman and C.E.O.
Asamera Inc.
Calgary

"Prospects for Indonesian Oil and Gas Development and Exports"

Mr. Wijarso, Expert Staff (Special Adviser)
to Minister of Mines and Energy
Jarkarta, Indonesia

"Exploration and Development Prospects in the Pacific Rim"

Malcolm W. Boyce, Vice President, Exploration
Chevron Overseas Petroleum Inc.
San Ramon, California

"Japanese Oil and Gas Situation (Supply and Demand to 1990)"

Akihiko Nomiyama, Director
Deputy General Manager, Petroleum Group
Nippon Mining Co. Ltd.
Tokyo, Japan

5:30 p.m. - 7:30 p.m. Reception Garden Terrace

7:30 p.m. Dinner, Macleod Hall "A"
J. Wallace Hopkins
Deputy Executive Director
International Energy Agency
Paris, France

TUESDAY, SEPTEMBER 16

8:45 a.m. - 10:15 a.m.

"THE IMPACT OF CANADIAN GAS DEREGULATION"

Moderator:
Norman E. MacMurchy, Assistant Deputy Minister
Policy Analysis and Planning Division
Alberta Department of Energy
Edmonton, Alberta

"A Producers' Perspective"

Douglas G. Stoneman, Chairman
Canadian Petroleum Association
Senior Vice President, Business Development
Shell Canada Limited
Calgary, Alberta

"A Distributors' Perspective"

Stephen T. Bellringer, President and C.O.O.
Union Gas Limited
President, Ontario Natural Gas Association
Chatham, Ontario

"Industrial Users' Perspective"

Harry Cox, Chairman
Industrial Gas Users' Association
Manager, Administrative Services
Cyanamid Canada Inc.
Niagara Falls, Ontario

10:15 a.m. - 10:30 a.m. Coffee Reception

10:30 a.m. - 12:00 p.m.

"THE U.S. AND CANADIAN HEAVY OIL MARKETS"

Moderator:
Walter W. Haessel, Vice President, Business Development
CERI Energy Research Ltd.
Calgary, Alberta

"Prospects for Heavy Crude Oil Development"

Richard F. Meyer, Research Geologist
U.S. Geological Survey
United States Department of the Interior
Reston, Virginia

"The Outlook for U.S. Heavy Oil Imports"

Jack W. Wilkinson, Chief Economist
Sun Company, Inc.
Radnor, Pennsylvania

"Developments in Canadian Heavy Crude Oil Markets"

Peter D. Hopkins
Western Crude Oil and Pipeline Manager
Esso Petroleum Canada
Calgary, Alberta

12:00 p.m. - 2:00 p.m. Luncheon

"North American Coal Developments"

A. Denny Ellerman, Executive Vice President
National Coal Association
Washington, D.C.

2:00 p.m. - 3:30 p.m.

"DEVELOPMENTS IN THE NORTH AMERICAN OIL INDUSTRY"

Moderator:
Clem W. Dumett
President
Unocal Canada Limited
Calgary, Alberta

"An Oil Pipeliner's Perspective"

R. Glen Caughey, Vice President, Projects
Interprovincial Pipe Line Limited
Toronto, Ontario

"Spot Sales, Futures Trading and Other Developments"

Jan B. Kay, Vice President, Marketing
New York Mercantile Exchange
New York, New York

"Developments in the Refining Industry"

Ronald G. Bruce, Manager, Administration and Computer
Application for North American Refining
Conoco Inc.
Houston, Texas

3:30 p.m. - 3:45 p.m. Coffee Reception

3:45 p.m. - 5:15 p.m.

"IMPACT OF U.S. AND CANADIAN REGULATORY CHANGES ON CROSS-BORDER TRADE"

Moderator:
D. Wayne Minion, Chairman
Northridge Petroleum Marketing Inc.
Calgary, Alberta

"The Impact of Canadian Regulatory Changes"

Roland Priddle, Chairman
National Energy Board
Ottawa, Ontario

"The Impact of U.S. Regulatory Changes"

Anthony G. Sousa, Acting Chairman
Federal Energy Regulatory Commission
Washington, D.C.

"The Impact on Canadian Gas Exports"

C. Ken Orr, President and C.O.O.
Western Gas Marketing Limited
Calgary, Alberta

5:30 p.m. Adjourn, Reception

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ENERGY PROJECTIONS

September 3, 1986

NUMBER 974

CHARLES T. MAXWELL
SENIOR ENERGY STRATEGIST
(212) 306-9378

WHY OPEC MAY SUCCEED IN SUPPORTING OIL PRICES NOW AFTER MANY PAST FAILURES

We believe that within 18-24 months, an oil price of $15 per barrel or so will be quite supportable based on economic factors alone -- that is, without assistance from a politically-devised reduction of supply such as now proposed by OPEC. The problem for OPEC, then, is to reach that point of supply/demand equilibrium two years out with its present pricing structure intact, given that the free working of markets probably would not maintain a $15 barrel over the interim period. Thus, OPEC is seeking to superimpose a political "wedge" of about $5 per barrel on top of the current economic price of oil (which we estimate at about $10 per barrel). This "wedge" must hold through the remainder of 1986, while surpluses from the OPEC summer output surge are still arriving in the market, and through the course of 1987, when there could be seasonal weakness in oil prices again in spring and early summer.

Can OPEC remain united in its policies and its execution of them for as long as 18 months to two years? If it can, we think the Organization will have successfully passed its most difficult test, and that economic pressures will then begin to work with OPEC instead of against it in supporting the price of oil in the mid-to-high teens. We are assuming an average price of $17 per barrel in 1988 and $20 in 1989, based on gradually tightening supply/demand ratios and on the present and anticipated letdown in oil exploration and development expenditures.

The immediate task before OPEC members is to reduce production to 16.8 million b/d and keep cheating to a minimum--say 200,000 b/d--so that supply and demand can be managed, and will equate at about 17 million b/d.

No one really knows if this can be done. However, our best guess is that OPEC may surprise the cynics and do it. We have not taken this tack in the past. The historical record is plainly against this view, and we fully appreciate the point. Nevertheless, we think there are some new elements affecting the situation, and these have pushed the odds in a different direction:

1. OPEC has seen and felt a $7/barrel oil price first-hand. This experience has been chastening. Members understand now what they could

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only imagine before--the devastation this can wreak on their societies. Thus, we believe they may be frightened enough to adhere to OPEC policy line.

2. Threats by Kuwait and Saudi Arabia to "open the valves" if they perceive other members cheating are all too believable today. Members know now what they did not last year: these two countries are prepared to act if their warnings are not heeded.

3. The rift caused by the Iraq/Iran war has created opposing political blocs within OPEC. The clash of these opposing sides has effectively immobilized the organization's reactive capacity even as prices have continued to fall to new lows. This rift may have been partly repaired through Iran's recent initiative with the Saudis at Geneva. We see this as essentially the opening of a political dialogue, whereas previously the two sides were only shouting slogans at each other. We believe these new lines of communication will be kept open. The Iranians desperately need the greater dollar revenue afforded by higher prices (they cannot export greater volumes). The Saudis want improved production discipline in OPEC and, at the same time, a free hand for their client, Iraq, to produce more. Both sides are essentially seeking a favorable arrangement for themselves. Still, their overlapping interests suggest they may be able to keep their OPEC allies in line on any settlement to which they both can agree.

4. OPEC's efforts to create a modest tightening in world oil markets is receiving some fortuitous help from unexpected quarters. Iraq's effective bombing of Iran's export terminals at Kharg and Sirri Island has not allowed Iran to utilize more than half its production quota in the past month. Air attacks on Iran's refineries have also sharply forced up imports of products from abroad. In addition, the U.S.S.R. has indicated that it will cut exports by 100,000 b/d. Mexico, Malaysia, and Oman have offered to reduce production by varying amounts, while Egypt, Brunei, and Norway may hold output even. All of these developments have given real and psychological help to oil markets at this time.

We think the odds are two to one that the existing pro-tem OPEC arrangement can be turned into a lasting agreement, and thus, that the price of oil can be maintained in late 1986 and through 1987 in the $14-$16 range (averaging $15 per barrel).

If this works out as we expect, growing institutional interest in oil stocks should follow. In support of this, we are also projecting rising earning power for the majors in 1988 (+ 15-18%) and 1989 (+ 25-30%).

The principal conundrum facing institutional fund managers at this time is not so much whether they should raise their weighting in oils (we think they should, and are recommending a move from 4% to a new level of 8%), but rather, which oil stocks are best placed to maximize returns. Many oil shares, in our judgment, have run up in price beyond fundamental value and visible earning power. They look "expensive." Still, we think there are ways through this dilemma. One of the most important of these is disciplined selection of issues. We will have more to offer on this subject, but Fred Leuffer's August 18, 1986 piece, The Outlook For Oil Stocks, is an excellent place to start the search for value.

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Additional information available upon request.

OPEC : WHAT NEXT

International Oil and Gas Markets Conference
Calgary, Alberta
September 14-16, 1986

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Riyadh , Saudi-Arabia

Note: The views expressed in this paper do not in any way reflect the opinion of the Saudi Fund for Development and are the author's alone.

OPEC : What Next

Introduction :

The Organization of Petroleum Exporting Countries (OPEC) is severely wounded and gasping for its last breath. We have witnessed a number of meetings this year, all the with objective to come up with a workable agreement acceptable to the whole group.

The purpose of this paper is to examine the current structure of OPEC and assess its future. It is our opinion that OPEC in its current structure will cease to exist by the mid 1990's. By then, a new and smaller organization will emerge as the new force in the world oil and petrochemical markets. This new "cartel" will be more stable, albeit subject to similar destabilizing forces that would tend to test its strength at times.

We will start with a brief theoretical discussion of the issues pertaining to the depletion of exhaustible resources and later outline the structure of the new oil cartel. Next, we extend the analysis to examine the international financial implications should the newly formed group of producers decide to abondon the U.S.Dollar as the means of payment for the sale of oil.

Resource Economics and the behavior of cartels :

The fundamental principle calls for the production of an exhaustible resource when the rate of increase of the net margin is less than the current rate of interest (discount rate). Should the reverse be the case, one leaves the resources in the ground and wait until it appreciates in value before starting to produce (see Hotelling 1931, Solow 1974).

The above does embody the assumption that the said producers enjoy a monopoly over the resource in question. However, such is not the case with OPEC. The members of OPEC are divided into two distinct groups : 1) the "cash starved" group which include all the countries with a low resource base and a large population (Nigeria, Algeria, Indonesia for example) and 2) the "rich" members of the cartel with small populations and a large resource base (namely, Saudi Arabia, Kuwait, U.A.E. and Qatar).

The policy implications of resource economics will be different for each one of the two groups. Ideally, the "cash starved" members would want to increase prices (this they are attempting to do through OPEC) and restrict output since each barrel produced today will be costly to replace tomorrow when their oil runs out.

Another observation on the theoretical implications for the oil policy of OPEC relates to the failure of the theory to predict the behaviour of an owner of an exhaustible resource who faces a cash-flow problem. Such a resource owner's optimum depletion path that would result from standard theory would be different from that which would alleviate the revenue or budget constraint. Because of an immediate need for revenue, "cash-starved" countries would increase their production of oil contrary to the predictions of resources economics. This behaviour is consistent with that of the said group in the current OPEC. The excess production over and above everyone's quota has been well documented in the press and this will not be treated here.

To conclude this short theoretical note, the cash-flow factor or revenue alters the production path (through the change of the discount rate) that the theory of exhaustible resources would dictate. It moves the production profile of the "cash-starved" members to the present and since the "rich" members of OPEC appear to prefer present production, their combined actions has lead to the current oil glut.

From OPEC to GOPEC :

By the mid 1990's we expect the Gulf Organization of Petroleum Exporting Countries (GOPEC) to displace the current OPEC as the new force in the world oil markets. The process will not be an abrupt one, but a natural transition to a more stable organization.

A few years from now, the "poor" members of OPEC (those with a small resource base and a large populations) will probably "exit" the organization for they would have exhausted their resource to the point where they have enough for their own internal consumption and the building of their industries. Then, we will see a new mini OPEC consisting of the Gulf members whose resource base is similar and, through the establishment of the Gulf Cooperation Council (GCC, which includes Saudi Arabia, Kuwait, Qatar, Oman, UAE, and Bahrain), have already the political and economic structure to work out internal disputes.

GOPEC's combined foreign resources stand at just over $ 200 billion at the moment. Furthermore, if one compares the average daily oil production of the rich members to that of the cash-starved group we find some startling results.

The population of Saudi Arabia, Kuwait, UAE and Qatar is estimated to be 14.29 million (1984 estimate) or a mere 4% of that of OPEC (excluding Gabon and Libya) which totals 357.67 million. Yet, the four Gulf Countries with only 3.8% of OPEC's population, produced almost 50% of Opec's oil production in 1985.

A relatively smaller population and a healthier financial status mean that GOPEC is definitely set to exert some control over the world oil markets in the mid 1990's. While it is true that all these GCC countries experienced a significant drop in revenue between 1984 and 1986 (see Table # 1), they are expected to wheather the current crisis better than the rest of OPEC.

GOPEC's characteristics and objectives will be different from those of OPEC. First, the number of producers is smaller, six as opposed to thirteen. The smaller number will make it easier for the group to agree on policy as well as to share information. Second, GOPEC will have an advantage over the previous cartel in that its members are all geographically located in one region of the globe. Third, the new oil producers own a significant portion of the world oil reserves (as of January 1985, 41%). If we include Iran and Iraq that share will be even greater (over 60%).

However, both Iran and Iraq are not members of the GCC and thus will not be part of GOPEC. Their presence in GOPEC will no doubt inject the same elements of instability that hobbles OPEC today. Once the war between Iran and Iraq ends, the world oil markets will be flooded with additional oil, making any attempt by OPEC (if it had to discipline them) to control production futile. With both nations outside GOPEC, the latter can better control them by strategically flooding the market itself. There are no doubt geopolitical considerations to be taken into account before GOPEC would do so. Nevertheless, the power to affect world oil market conditions will still rest with that group.

Table 2 gives the projection of future oil production until the year 2000. From it, we can see that the shares of oil production decline in every major part of the world except in Mexico and OPEC. Mexico will experience a 2% increase by the year 2000 while that OPEC (particularly the Gulf) will increase to 56% by the same year.

Further evidence of future GOPEC's dominance is given in Table 3. The most notable thing is the production as a percentage of capacity. OPEC is forecast to be producing at 105% of its capacity, by 1995 while during the same periods (1986-1995) non-OPEC production will experience a decline.

Most of the excess capacity is presently in the hands of GOPEC, so we can safely assume that they will be producing at close to full capacity.

Long Term Pricing Policy:

Natural resource economics would dictate a long term depletion rate for these countries that is consistent with their development goals. All have a limited absorptive capacity, which should translate into a relatively slow depletion rate of oil overtime. But more importantly, the large resource base should also dictate a long term pricing policy that is characterized by a stable growth of oil prices over the years (consistent with world inflation, oil demand etc...) and not by sharp jumps as experienced in 1973/74 and 1979.

The latter will, as the new producers know, bring about a new round of conservation measures, accelerate the process of de-energization of industry worldwide and may further stimulate the production of oil substitutes. Finally, as mentioned earlier, the political union in the form of the GCC will add further stability to the organization.

Unlike OPEC, GOPEC will be more involved in the world market of petrochemicals. Thus its role will extend beyond the production and sale of crude oil. Some of the members have invested considerably in downstream operations, and we should expect them to play a significant role in the future.

Short Term Solutions for Opec:

As for OPEC, it will muddle through the transition period at a great cost to the whole group. No one should have been surprised at the past and current problems of the organization. They are nothing but a true reflection of the workings of a cartel. OPEC was born with a "cancer" that would ultimately diminish its role over the coming years but not take it completely out of existence.

The members of OPEC may have been "blessed" with the ownership of a valuable resources, but not without a cost. Unlike GOPEC, the members of OPEC started with vastly different levels of oil reserves and financial needs. From day one, what was acceptable to one member was not necessarily acceptable to another. The job of the organization has thus been to try and agree on a long term strategy of pricing and production.

To address the problem during the transition to GOPEC, OPEC needs to come up with a new approach that has to transcend political differences within the group. Some members of OPEC will at times (despite the latest Geneva agreement) produce over and above their quotas. This cheating is basically the result of a decline in demand for oil, coupled with the fact that the "poor" members within OPEC need revenue now as opposed to tomorrow. This cheating will continue until the cost of doing so becomes considerable to everyone.

The policy, then, should be to assist those members of OPEC that need help in order to prevent them from having to resort to discounting or dumping their crude in the spot market. OPEC should establish a balance of payment "support program" whose primary function is to "tie" those countries that develop balance of payments difficulties. Of course the problem of deciding who needs help and how much of it would have to be dealt with by the group as a whole. One is assuming that the benefits of the balance of payment support program outweigh the costs to the group.

We are presently witnessing a group that appears to be going through the motions of meeting for the sake of doing so, but once home, everyone does as he pleases. The question to be asked by OPEC is really simple. Do we, as an organization, want to maximize the revenue of the group as a whole or are we going to be selfish and have each one of us go it alone? If the answer is yes for the group, then, OPEC should seriously consider the establishment of a balance of payment support program.

Gopec's stability:

The Gulf Organization of Petroleum Exporting Countries (GOPEC) will undoubtedly be more successful in agreeing to a long term pricing and production strategy not only for crude oil but for petrochemicals as well. It will also be free from most of the problems currently affecting OPEC.

We are in effect in a period of transition. The change over from OPEC to GOPEC will be a natural transition. The size of the new organization, its imprtance, and its role will be different from that of OPEC. We should look to a more stable organization. The Gulf members will have to place more emphasis on petrochemicals and distribution networks. The next step will be to address the strong protectionist tide that is currently sweeping across Europe and the United States. The Common Market has already applied a thirteen and a half percent tariff on Petrochemicals from the Middle East. In the United States, the Gibbons bill in the House, aimed at alleged Saudi "dumping", is the opening wedge in what could be a sustained attack on a vital export business of the future GOPEC.

GOPEC : ROUND TWO

Pricing of Oil: Which currency ?.

The setting of GOPEC by the members of the Gulf Cooperation Council (GCC) is but a first step towards a major restructuring of the world oil and petrochemical markets. Once that is achieved, the members must shift their attention to an issue that has been plaguing the current OPEC for years and will no doubt consume GOPEC's energy too : what currency must it use to price its oil and oil products?

The dollar has long been established as "the" acceptable means of payment. Now is the time to think about the problems associated with pricing the only resource they have in terms of a major currency. Not only must GOPEC (and every other oil producing nation) constantly worry about the value of the dollar (the value of which has been declining for most of the year) , but about the state of demand for oil as well. Pricing oil in dollars, a currency over which GOPEC has no direct influence, has a dual impact on the organization. First, whenever the dollar appreciates against other currencies and particularly the western consuming nations, it affects the latter's demand for oil on the downward side.

True, GOPEC might see its purchasing power slightly increase but not by much. Even less when both the price of oil and the value of the dollar go up. Second, as the 1970's proved, the dollar can depreciate at the same time that oil demand increases leading to a further erosion of the value of oil revenue.

GOPEC then, should detach itself from the use of the dollar as a pricing unit. This does not mean that part of the actual payment (or in some cases all of it depending on how much trade is done with the United States) need not be made in dollars, but only that the eventual dollar price will be computed from a basket containing a number of currencies.

The Basket Idea: The European Currency Unit (ECU).

Pricing oil in terms of a basket of currencies is not something new. During the seventies, the SDR (special drawing rights) was mentioned as an appropriate accounting unit to counterbalance the effect on oil revenue of the declining dollar. The idea never saw the light because OPEC was too busy arguing over other issues affecting the organization at the time. Furthermore, this can only be achieved from a position of strength and with a stable organization such as the future GOPEC will be.

We propose a two part approach. In the first part, oil and oil products should be priced in terms of the European Currency Unit (ECU) in addition to the yen and to some extent the US dollar. Deciding on the proper weights for each of the currencies will not be easy. Since the transition to a different pricing unit will be technically difficult, using the ECU may be a good start. Use of the ECU is gaining acceptance rather rapidly and its adoption by GOPEC will help quicken that process. Furthermore, Europe and Japan are both important trade partners for GOPEC's oil and oil products.

By pricing oil in terms of ECU's the producing countries will help stabilize the purchasing power of the proceeds from the sale oil. They will also be able to forecast future revenues and thus achieve better planning of development projects. On the demand side, the consuming countries (and

particularly the poor developing countries) will not have to constantly buy dollars in the open market and be subject to the often wide fluctuations of that currency. As a result, the developing countries will be in a better position to plan expenditure on energy and better allocate the remaining part for development purposes. An additional benefits relates to the servicing of the international debt. 90% of the public and publicly guaranteed fixed rate of interest debt and 58% of the floating rates of interest debt are in dollars.

De-emphasizing the use of the dollar will not only help stabilize its value (thus ease the repayment of the debt) but will also help give the incentive for the debtor countries to lessen the share of the dollar in their future debt. This will become more crucial, now that aid from the rich oil exporting countries is drying out due the weak world oil markets.

Because of the importance of the dollar as an international medium of exchange, countries around the world are affected by the monetary and fiscal policies pursued by the United States.To change that, we simply have to "redefine" what is acceptable as an international medium of exchange or means of payment.

Adoption of the ECU (in the first part) should considerably lessen the pressure on the U.S.Dollar in the international currency markets. U.S. monetary policy, as a result, will not always be frustrated. Furthermore, the resulting average level of the dollar will help the U.S. export industry and thus alleviate the pressure from the large U.S. trade deficit. This eventual result does assume that oil payments are made in currencies other than the dollar, but no totally excluding it.

In the limit, the international demand for dollars may stay constant if oil producers insist on being paid in dollars. That, however, is an unlikely outcome.

The second Round: The GCU:

In the second part, GOPEC should attempt to price its oil in terms of the Gulf Diner, or what we will call the eventual "GCU" or Gulf Currency Unit. By that time, the financial structures of the Gulf members would have matured to sustain any major operation on the GCU.

Implications for the members of GOPEC will vary depending on the exchange rate system they choose. If the members stick to the current system (which can be qualified as a managed float, where the individual currencies are tied to a basket of major currencies) then the effect will be limited. If, however, they opt for a flexible exchange rate system they would experience effects similar (but not with the same intensity) to those experienced by the United States. In any case, there has to be a demand for GCU's and that, in all likelihood, will be limited to the companies doing business in the area.

Finally, having a national or in this case a regional currency unit open to international speculation assumes two things. One, that the country or region in question has a sophisticated and well developed financial structure with the necessary monetary instruments to intervene in the market. Two, that the authorities have the foreign reserves necessary to support the said currency. The Gulf members will overcome the second constraint. However, at this time their financial structure may not be developed well enough to sustain a major operation on the GCU. Similar to pricing oil in ECU's,

expressing it in terms of GCU's does not necessitate payments in the currencies of that unit of account. In fact, one would expect the oil producing countries to continue demanding payment in a number of currencies other that their own. Pricing oil in terms of GCU's would give them better control of the eventual purchasing power of oil and oil products proceeds and thus complete their attempt at having a greater say in world oil matters.

TABLE (1)

IMPACT OF LOWER OIL PRICES ON GULF CONTRIES OIL REVENUES

	1984		1985*		1986*	
	Production (mb/d)	Earnings ($million)	Production (mb/d) (1)	(2) Earnings ($million)	Production (mb/d)	(3 Earnings ($million
Saudi Arabia	4.10	36,186	3.25	27,367	4.35	19,069
Kuwait	1.16	12,345	1.06	10,994	1.32	7,127
U.A.E	1.10	11,707	1.05	10,890	1.30	7,022
Qatar	0.38	4,225	0.30	3,130	0.30	1,682
Oman	0.42	3,829	0.50	4,440	0.55	2,540
Bahrain	0.04	1,008	0.04	958	0.04	527

Source : Compiled from National and International sources includin International Energy Agency, Paris, April 1986. IMF, International Financia Statistics, April 1985.

GCC : Central Banks and Monetary Agencies Annual Reports (various issues 1983-1985).

* Estimates

** Projections

(1) Based on average production of 3.7 mb/d in first quarter, 2.7 mb/d in th second quarter, 2.4 mb/d in the third quarter and 4.2 mb/d in the fourt quater.

(2) Average price per barrel of Gulf oil Estimataed at $27 compared to a average price of $28.3 in 1984.

(3) Projections based on an average price per barrel of Gulf crude oil of $1 in 1986.

Source: Gulf Econnomic and Financial Report. Issue #6, June 1986, Vol 1 p.2.

TABLE - 2

CRUDE OIL PRODUCTION

NON COMMUNIST WORLD

MILLION BARRELS PER DAY

	% Annual Change		% Share	
	90/85	2000/90	1985	2000
U.S.	-2.4	-2.4	23	13
W.Europe	0.4	-3.0	10	6
Mexico	0.9	3.9	7	9
Other	1.7	-0.6	18	16
OPEC	2.4	3.8	42	56
TOTAL	0.9	1.5	100.0	100.0

SOURCE: World Energy Outlook
Chevron Corporation, June 1986 Page 10

TABLE - 3

PROJECTIONS OF OIL DEMAND AND SUPPLY THROUGH 1995

(MB/D)

	1986	1987	1988	1989	1990	1995
Average Price in Real Terms ($ per Barrel)	14	47	19	21	23	30
(1)						
Consumption	46.4	47.0	48.0	49.0	50.0	55.0
Industrial Countries	34.7	35.0	35.4	35.8	36.0	38.0
Developing Countries	11.7	12.0	12.6	13.2	14.0	17.0
(2)						
Non-OPEC Production	28.0	27.5	27.0	26.5	26.0	24.0
Requirement from OPEC	18.4	19.5	21.0	22.5	24.0	31.0
Natural Gas Liquids	1.4	1.5	1.6	1.7	1.8	2.0
OPEC Production (Crude Oil)	17.0	18.0	19.4	20.8	22.2	29.0
OPEC production Capacity	25.0	25.7	26.2	26.6	26.9	28.0
Production as % of Capacity	68	70	74	78	82	105

1) Excluding Communist Countries

2) Including net oil exports to the West from the Communist Countries.

SOURCE: Gulf Economic and Financial Report
Issue # 6, June 1986 - Volume 1.

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A Global View of Gas Reserves and Markets

By

Richard L. Itteilag

Diretor, Gas Demand Analysis

American Gas Association

Before

The International Oil and Gas Markets Conference

Calgary Convention Centre
Calgary, Alberta, Canada

September 15, 1986

Part I

U.S. Natural Gas Production Capability -- 1986-1990

Long-term supply is still not a problem. There is currently 160-170 Tcf of proven reserves or 10 years of production at 17 Tcf/yr. Add to that about 650 Tcf of potential gas leaving over 50 years of production. Now, having said that, let's dispense with the "gas bubble."

Excess natural gas production capability (the "gas bubble") increased to 3.6 Tcf in 1985 as a result of reduced gas requirements. The bubble will decrease significantly in 1986 to 2.6 Tcf and will be only 947 Bcf in 1988. By 1990 the bubble will be effectively dissipated and gas supplies and requirements will be in balance. Three factors will cause the bubble to shrink: (1) declining domestic production capability due to reduced drilling (the product of low prices and shut-in production); (2) higher gas demand due to lower natural gas prices; and (3) stability in Canadian gas imports. After 1988, the bubble will have shrunk enough to spur drilling activity and after 1990 reverse the decline in production capability. Reduced consumption of natural gas from the 1975-81 average of 19.7 Tcf per year, coupled with nearly constant domestic gas delivery capability from 1980-1985, led to the "gas bubble".

The estimates developed here are intended to evaluate what production levels might be achieved with wells already drilled and attached to pipelines. Some additional capacity also exists in wells that are capable of gas production but have not been completed or are not connected to a pipeline. In addition, there are large volumes of gas behind the pipe (gas not being produced because production from that well is presently coming from other depths) which are excluded from production capability. In both situations these volumes of gas represent a capability that is not utilized.

The unused production capability has increased significantly since 1979. The unused capability rose rapidly to a peak level of 4.6 Tcf in 1983 and then started to decline. The decline is primarily due to a reduced drilling activity and a decline in the rate of increase of producing gas wells. The declining production per gas well is counterbalanced by the increasing number of producing gas wells. From 1979 to 1985 these factors were in equilibrium so that production capability remained nearly constant at about 20-21 Tcf. The assumed decline in drilling (resulting from the low rig count levels) reduces the rate of growth in the number of producing gas wells after 1985. The decline in production per gas well becomes a dominant factor in this time period so that the total productive capacity declines from 20,023 Bcf in 1985 to a low level of 17,303 Bcf in 1990. This in turn causes a decline in the "bubble size" from the 3.6 Tcf of 1985 to essentially zero in 1990.

Reserves, therefore, are still strong. Prior to 1978 (NGPA) replacement reserves were only 46%, while from 1981-85 the rate rose to 92-93%. In 1985 reserve additions are estimated at 75-82% of production.

PART II

World Natural Gas Consumption Trends

Before the oil crisis of the 1970s, the U.S. dominated the annual world gas statistics, producing and consuming more than half of the world's gas. Since then, European, USSR and Asian natural gas usage has increased by 180 percent. By 1984, U.S. production had declined to only 30 percent of the world total, indicating that the importance of gas in foreign economies had increased dramatically. At the beginning of the 1970-1984 period, natural gas provided less than six percent of the total energy in key European industrial nations such as the UK, France and West Germany; now the percentages of their total energy needs which are satisfied by gas are 25, 16 and 13 percent, respectively. By 1984 the USSR gas use had grown by more than 180 percent as compared to 1970.

World gas usage patterns between 1970 and 1984 continue to show a decided movement toward increased use of natural gas. Some key features of this trend are:

- World gas consumption rose at an average annual rate of 3.2 percent from 1970 to 1984.
- Western Europe established a 9.8 annual percentage growth rate for gas consumption from 1970 to 1980.
- Of the world's leading industrial nations, the greatest absolute growth in energy consumption from 1970 to 1984 was in the USSR which reported an average growth rate of 7.7 percent per year.
- In the important categories of annual production and exports, the USSR now ranks first.

World gas production has increased steadily since 1975. The average rate of increase was 2.7 percent per year from 1975 to 1984. Gas production increased the most in the USSR. In 1970 the USSR production was only 7,008 Bcf per year. By 1984 the USSR produced 36 percent (21,060 Bcf) of the world's gas at a level three times greater than the 1970 level - an annual growth rate of 8.2 percent. Available evidence of Soviet pipeline construction, field development and gas reserves indicate that this rate of increase may moderate but continued increases in production capability are likely.

Production in the western industrialized nations other than the U.S. could be generally characterized as maximization of the indigenous production capability and absorption of the rises and falls of national gas demand in the domestic production share. For example, Canada, the UK and the Netherlands are three of the most important western producing nations. Canada and the UK production levels dropped from 1975 to 1984 despite the fact that national consumption levels increased. In the Netherlands both production and consumption levels decreased. In Australia/New Zealand production and consumption grew rapidly as the gas resources of this area were developed and the gas infrastructure came into being.

In the other western industrialized nations production levels declined slightly. In some cases this was a result of aging of the production wells and so reflect a loss in national production capability which has not been offset by the drilling of new gas wells. In other cases it represents a decline in production to offset the increase in imports which were contractual commitments.

Of the European nations, West Germany is the largest importer of gas with the 1,471 TBtu in 1983 coming primarily from the Netherlands and USSR. The importance of gas from the Netherlands and USSR to Belgium and Luxembourg, France, West Germany and Spain is the fact that these imports are more than 90 percent of the total national gas consumption. The dominance of the USSR as a world exporter of gas is clear in that over 2 quadrillion Btu were exported in 1982.

Part III

U.S. Natural Gas Demand in New Markets

To place the total gas supply/demand outlook in full perspective, demand levels for traditional markets were added to the new, non-traditional market forecasts for the year 2000. Total gas demand, therefore, is expected to grow from the 1985 level of under 18 Tcf to 19.20 Tcf in 2000 even in the BAU Case. In the Attainable Case gas demand could reach 23 Tcf, a level consistent with consumption trends in the early 1970s, while in the Potential Case gas demand could be as high as 27 Tcf.

Cooling -- The natural gas cooling market, which includes absorption chillers, dessicant and engine-driven systems, as well as gas-fired heat pumps, under the assumptions of the Attainable Case, is expected to grow rapidly from 0.04 Tcf of gas in 1985 to 0.07 Tcf in 1990, 0.37 Tcf in 2000 and 0.85 Tcf in 2010. The development of new, high efficiency gas equipment, combined with increased demand for cooling from commercial buildings will result in as much as 1.9 Tcf by the year 2010 in the Potential Case. The commercial gas market share would be 18% in the Attainable Case in 2010 or equivalent to adding cooling customers at a rate of only 1 per 75 total new customers. The competitive economic advantage today of gas cooling over electric cooling by region can be seen as the life-cycle costs of gas equipment are consistently below the electric equipment costs under best-case conditions when off-peak gas rates compete with peak summer electric rates for 30, 250, and 500 ton units.

Cogeneration -- Cogeneration which includes gas turbines, boiler/steam turbines, internal combustion engine driven systems, packaged systems with absorption chillers used in a bottoming cycle, and fuel cells, is a major gas market today, accounting for 0.7 Tcf of gas consumption. The forecast shows that under the assumptions for the Attainable Case this market will grow gradually until 1990 (0.8 Tcf) and then increase more rapidly to 1.2 Tcf in 2000 and 1.3 Tcf in 2010. The slower growth in the next five years, which follows a period of rapid growth between 1980 and 1985, is attributable to excess electric capacity and a moderation in demand in the West and Southwest regions of the country. However, the Attainable Case forecasts through 1990 may prove conservative as gas demand increases in other emerging regional cogeneration markets, particularly the Northeast. The potential demand for cogeneration in the year 2010 is 2 Tcf. Food, textiles, and chemicals are by far the most attractive industries for cogeneration

Select Use -- The select use of gas, which includes reburning with gas for NO_x reduction and the use of gas for dry sorbent injection for SO_x removal, currently consumes 0.05 Tcf, and is expected to increase rapidly. Demand of 0.2 Tcf in 1990, 0.3 Tcf in 2000, and 0.5 Tcf by 2010 is projected in the Attainable Case. The extent and timing of environmental legislation that encourages gas use and reduces plant emissions from coal and oil will be the major determinant of select use gas demand. By the year 2010, demand could range between 0.2 Tcf and 1.2 Tcf. There are many examples of select gas use applications currently in use today in various states in conjunction with oil and coal use.

Combined cycle -- Combined cycle power plants, which combine gas turbines, steam turbines and heat recovery generators, consumed 0.1 Tcf in 1985. In the Attainable Case, demand for this end use is expected to steadily increase to 0.4 Tcf in 1990, 0.6 Tcf in 2000 and 0.7 Tcf in 2010. The rate at which coal and nuclear plants come into service will influence gas demand from combined cycle units, which has a potential demand of 1.4 Tcf by 2010. A 240 megawatt gas combined cycle plant today is more cost effective than a coal-fired plant. On a cents per kilowatt hour basis for base load operation, the gas combined cycle plant's capital costs are about one third of the coal plant's capital costs.

CNG Vehicles -- The use of gas as a vehicular fuel is expected to reach 0.11 Tcf in 2000 under the assumptions of the Attainable Case, from a negligible amount in 1985. No significant gas penetration in this market is envisioned until after 1990. The economics of conversion vehicles, particularly fleet vehicles, will determine the demand level. Keep in mind that oil imports could rise dramatically in the future. According to a sensitivity analysis by DOE, if world oil prices reach only $20/bbl in real terms by 1995 instead of growing to $30/bbl in DOE's Base Case forecast, oil imports would more then double from about 5 million barrels per day today to 11 million barrels per day (BD). CNG vehicles could offset some of these oil imports in a stronger energy security policy. By 2010, CNG vehicle demand could reach 0.28 Tcf or about 150,000 BD equivalent. The conversion of heavy diesel trucks to CNG is considered the most attractive option for widespread early development of CNG. Typically they use larger engines and operate more hours making it easier for fuel cost savings to offset the cost of engine conversion. Heavy trucks consume diesel fuel in the amount equivalent to 1.4 Tcf of natural gas today and make up 17% of the miles traveled of all trucks.

The gas industry market profile could look significantly different in 2000 and 2010 than it looks today with the development of these new markets. In order to achieve the demand levels outlined here, there must be an industry commitment to seek new marketing and regulatory options and to invest in specific R&D programs. There must also be a recognition by regulators and legislators that increased gas use via these markets benefits the nation and should be supported.

Table

Natural Gas Consumption
(in 10^{12} Btu)

Country	1970		1975		1980		1983		1984	
	Consumption	Share	Consumption	Share	Consumption	Share	Consumption	Share	Consumption	Share
Australia/ New Zealand	59	.03	196	.07	392	.11	532	.15	576	.15
Austria	98	.12	144	.15	168	.16	152	.16	172	.17
Belgium & Luxembourg	164	.09	384	.21	412	.20	328	.19	336	.18
Canada	1,275	.20	1,724	.22	1,972	.22	1,892	.22	1,912	.22
China	129	.01	348	.02	468	.02	428	.02	432	.02
France	363	.06	680	.10	944	.12	888	.12	940	.13
Germany (FRG)	507	.05	1,376	.14	1,776	.16	1,564	.16	1,644	.16
Italy	480	.10	720	.14	916	.16	904	.16	1,060	.19
Japan	140	.01	308	.02	936	.07	1,008	.07	1,324	.09
Netherlands	745	.32	1,328	.47	1,212	.41	1,180	.46	1,248	.47
Spain	4	-	52	.02	72	.02	100	.03	96	.03
UK	437	.05	1,316	.16	1,656	.20	1,760	.23	1,808	.24
USA	22,000	.34	19,936	.29	20,284	.28	17,420	.25	18,320	.25
USSR	6,201	.21	9,200	.24	13,120	.28	16,200	.31	17,576	.33
Western Europe	2,798	.07	6,000	.13	7,156	.14	6,876	.15	7,304	.15
World	36,219	.18	43,176	.18	51,872	.19	53,020	.19	56,396	.20

Source: BP Statistical Review of World Energy, June 1985.

Table 2

Natural Gas Production
(in 10^{12} Btu)

Country	1975	1980	1983	1984	Percent of World Production 1984
Australia/New Zealand	220	436	544	640	1
Canada	2,756	2,764	2,504	2,608	5
China	356	488	432	460	1
France	276	280	220	212	-
Germany (FRG)	548	564	524	524	1
Italy	524	412	444	468	1
Japan	88	80	56	56	-
Netherlands	2,748	2,756	2,444	2,460	4
UK	1,276	1,280	1,224	1,260	2
USA	19,628	19,800	16,360	17,576	30
USSR[1]	10,416	15,208	19,296	21,060[2]	36
World	45,276	53,756	54,188	57,776	100

[1] USSR production in 1970 was 7,008 TBtu.

[2] Preliminary estimates for 1985 production in the USSR, reported by the U.N. Economic Commission for Europe, are 22.3 Tcf. See International Butane/Propane Newsletter, February 18, 1986.

SOURCE: BP Statistical Review of World Energy, International Energy Statistical Review, National Foreign Assessment Center.

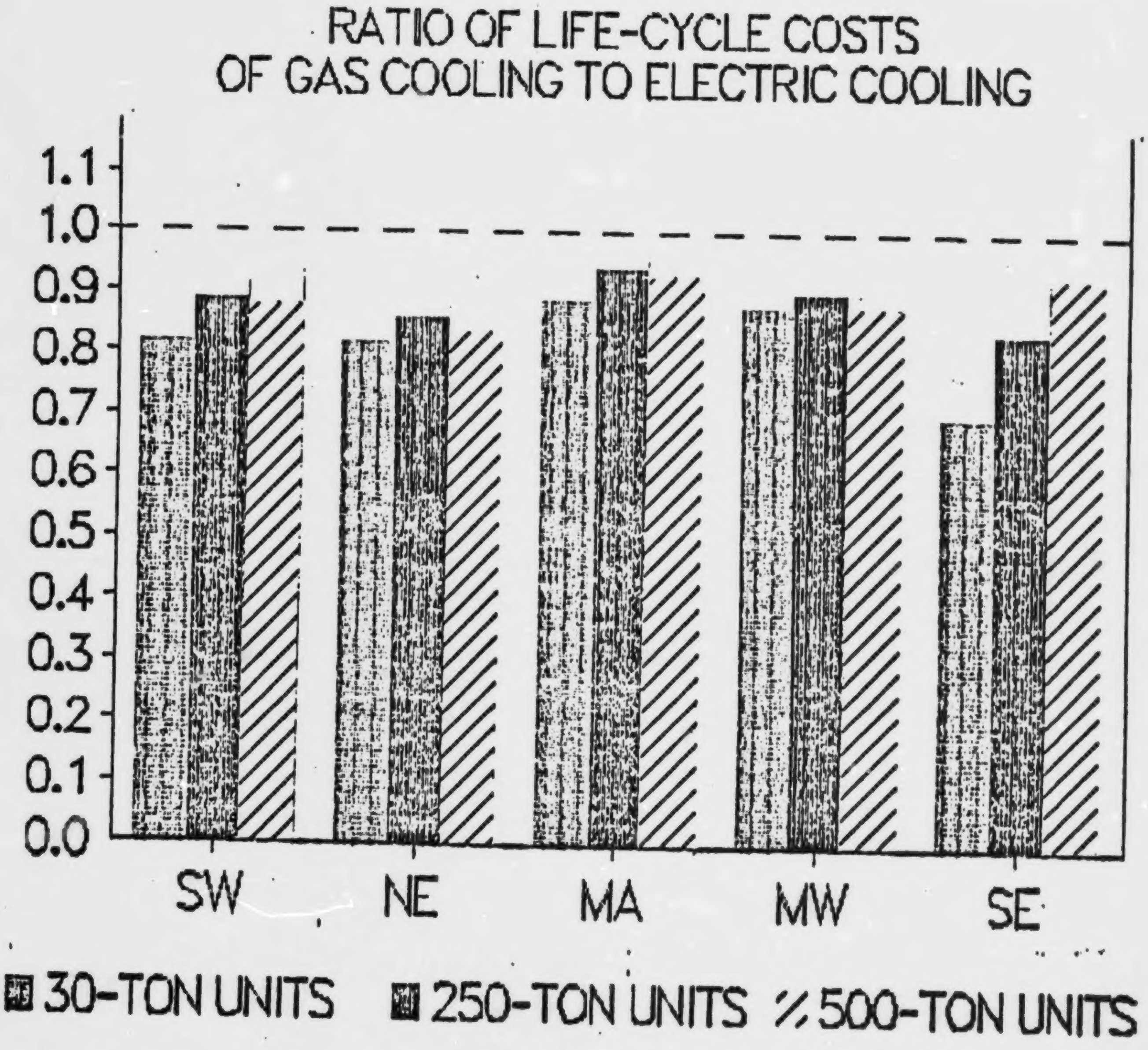
TOTAL GAS DEMAND (Tcf)

	1985	2000		
		BAU	Attainable	Potential
RESIDENTIAL	4.82	4.30	5.10	5.60
Cooling	0.01	0.03	0.08	0.15
COMMERCIAL	2.05	3.20	3.90	4.60
Cooling	0.03	0.06	0.29	0.64
INDUSTRIAL	6.57	7.40	8.20	8.30
Cogeneration	0.70	0.80	1.20	1.70
ELECTRICAL GENERATION	2.99	2.50	2.60	2.70
Select Use	0.05	0.10	0.30	1.00
Combined Cycle	0.10	0.30	0.60	1.20
TRANSPORTATION	0.51	0.50	0.60	0.60
CNG/Gasoline Vehicles	-	0.01	0.04	0.19
CNG/Diesel Vehicles	-	-	0.07	0.13
TOTAL	17.83	19.20	22.98	26.81

GAS COOLING DEMAND
Attainable Case

(Tcf)

1985	1990	2000	2010
0.04	0.07	0.37	0.85


RATIO OF LIFE-CYCLE COSTS
OF GAS COOLING TO ELECTRIC COOLING
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
SW
NE
MA
MW
SE
30-TON UNITS
250-TON UNITS
500-TON UNITS

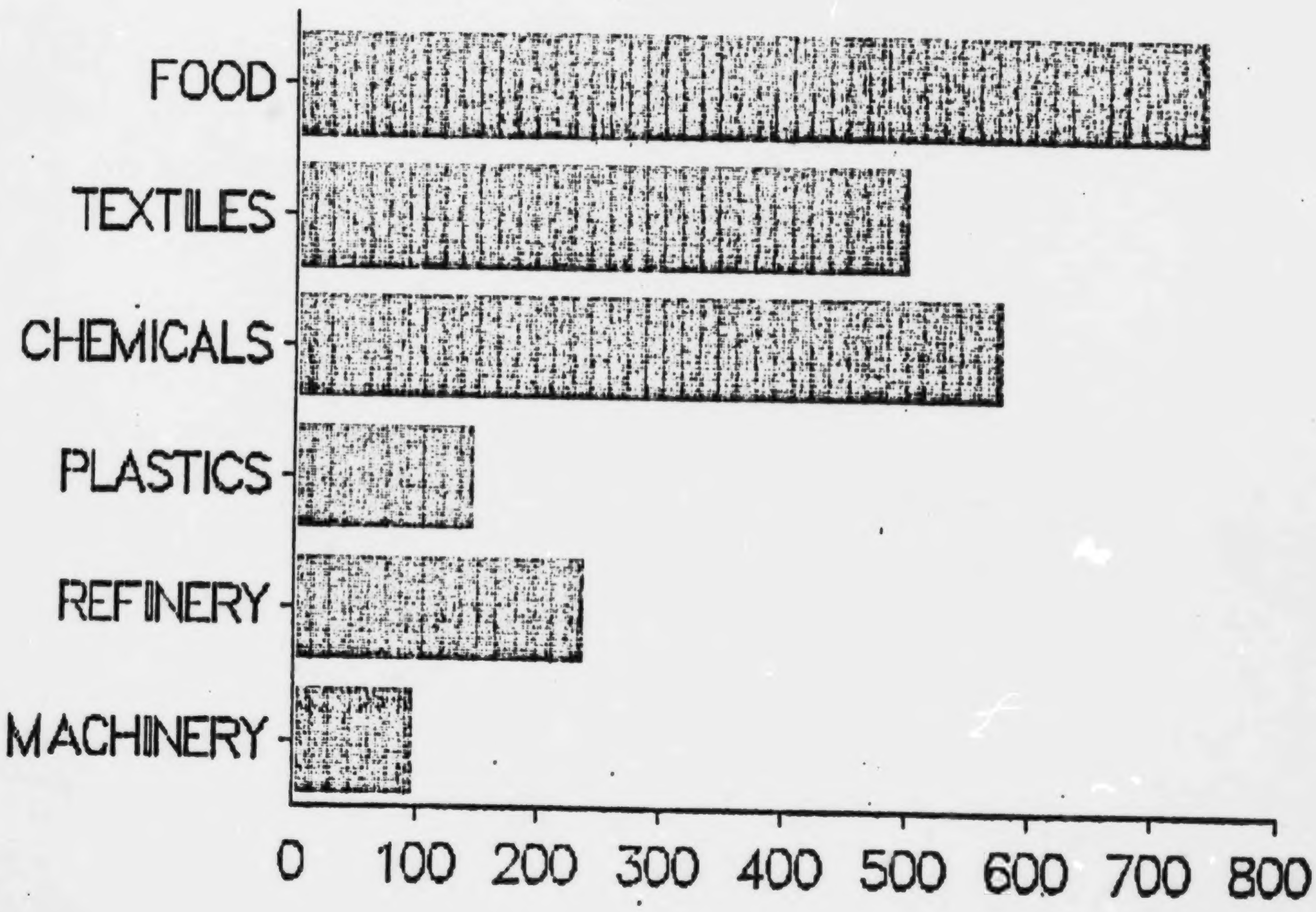
GAS COGENERATION DEMAND

Attainable Case

(Tcf)

1985	1990	2000	2010
0.7	0.8	1.2	1.3

POTENTIAL COGENERATION PLANTS BY INDUSTRY



SELECT GAS USE DEMAND

Attainable Case

(Tcf)

1985	1990	2000	2010
0.05	0.2	0.30	0.5

EXAMPLES OF SELECT GAS USE APPLICATIONS

State	Company	Gas Used In Conjunction With
AL	3M	Oil
CT	Uniroyal	Oil
MO	Springfield Utilities	Coal
NJ	Public Service E & G	Coal
PA	U.S. Steel	Coal
RI	Narragansett Electric	Oil
VT	Burlington Electric	Oil

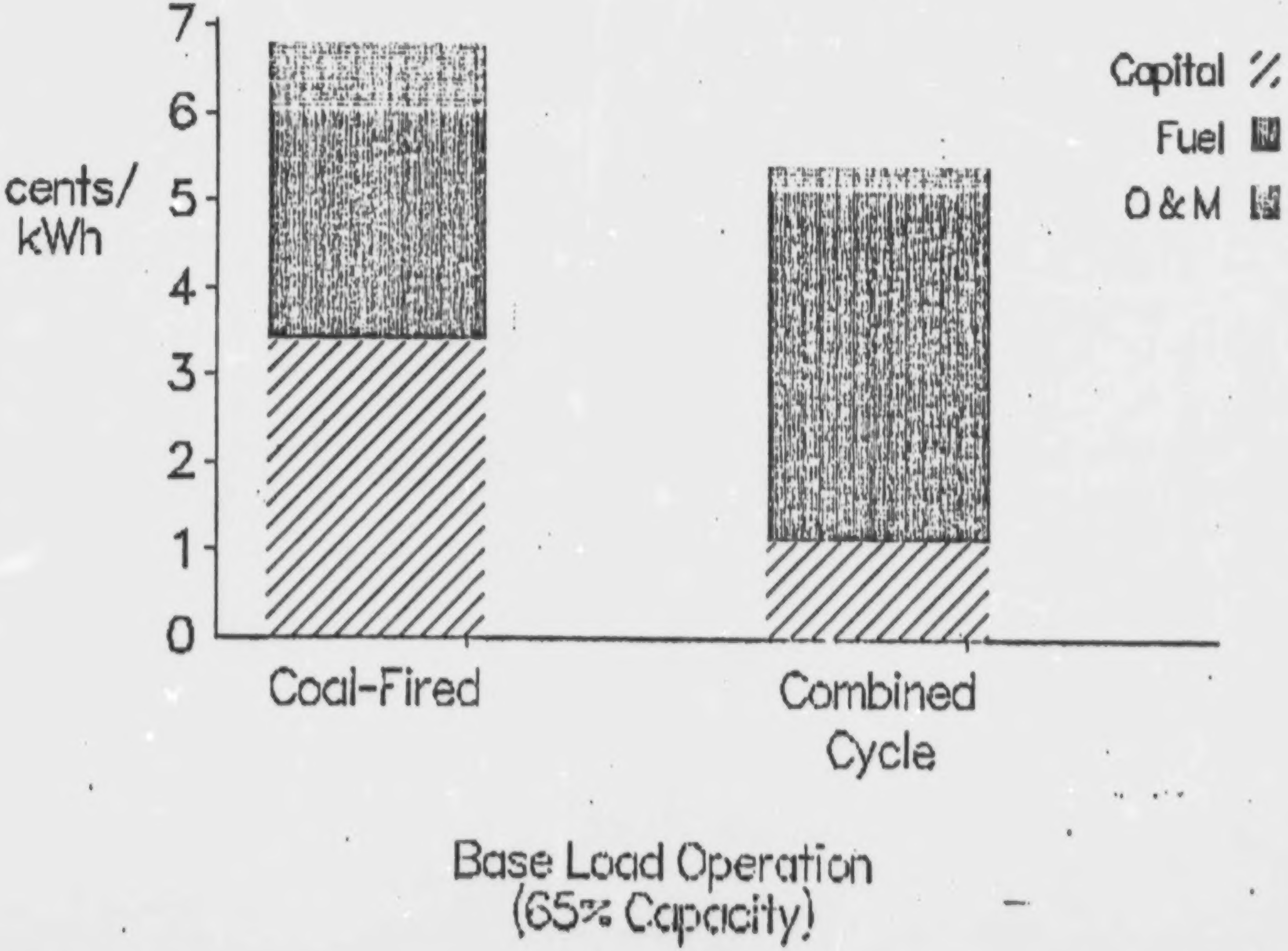
GAS COMBINED CYCLE DEMAND

Attainable Case

(Tcf)

1985	1990	2000	2010
0.1	0.4	0.6	0.7

240 MEGAWATT POWER PLANT COSTS
COAL VERSUS GAS COMBINED CYCLE



CNG VEHICLE DEMAND

Attainable Case

(Tcf)

1985	1990	2000	2010
---	---	0.11	0.28

1982 DIESEL TRUCKS

	Number Registered (000's)	Avg. Miles Traveled Per Truck	Fuel Consumption Avg. Miles/gal.	Tcf Per Year
TOTAL DIESEL	1,630.9	38,810	10.6	1.4
ALL TRUCKS	33,834.4	11,150		
% DIESEL	5%	17%		

THE INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

CALGARY, 14-16 SEPTEMBER 1986

Speech given by D J WRIGHT
Energy Economist - Commission of the European Communities

GAS DEVELOPMENTS IN EUROPE

(The remarks made below are the authors' own views and do not necessarily reflect those of the Commission of the European Communities)

GAS DEVELOPMENTS IN EUROPE

Ladies and Gentlemen,

Let me start by saying how pleased and grateful I am for having the opportunity today of addressing this conference. Not only is the Conference in one of my favourite countries in the world - but it is also in one of my favorite locations here in Calgary. I would like to thank both the Canadian Energy Research Institute and the Calgary Chamber of Commerce for their kind invitation.

1. Introduction

Although it is notoriously difficult to get economists to agree on anything, perhaps energy economists the world over would agree that 1986 has been a very long year.

Here we are, only at the end of the third quarter of 1986, and already this year we have had to contend with the dramatic volatile fall in oil and energy prices (and now a significant rebound) which has played havoc with our forecasts, investment plans, even our cash flows. But on top of this, on the continent of Europe during the weekend of 26 April 1986 news began to filter out of the Soviet Union of the worst nuclear accident in history. Already both events have led to important changes in political opinion in Europe. Both events could end up having profound effects on our energy futures as well.

At the same time, although perhaps less noticed on this side of the Atlantic, there has been a very important change in the perspectives in the European gas industry. Very recently the Norwegian oil group

Statoil and its co-owners of two prodigious North Sea gas fields (Sleipner and Troll) have agreed a deal with a European consortium of buyers on the supply of large volumes of natural gas beginning in the 1990's to four European countries.

In the time available to me I want to concentrate on these three events which already have had, and may have in the future, the profoundest effects on European gas markets. I will do this first considering short-term gas developments and then focussing on the longer-term issues for gas. The other subjects that will come up in this brief review of gas developments in Europe will be future pricing possibilities for gas and the gas security issue.

2. Background on the European Community's gas industry

Natural gas is a vital energy source in Europe. It now covers 18% of the European Community's energy requirements - slightly less than in Canada and the United States - and considerably less than in the Soviet Union. The share of natural gas in European energy demand has steadily increased in the 1970's as the gas network spread out from the main North/South and East/West pipelines. The expansion of natural gas in the European Community has helped reduce dependence on imported oil as well as diversifying overall energy supplies.

TABLE 1

Share of Natural Gas in Energy Consumption

	1975	1985	Source
EEC-12	15.5%	18%	EEC
Canada	21.4%	21.5%	IEA
United States	27.7%	21.6%	IEA
USSR	24%	34%	BP

The European Community's own resources of natural gas are around 3 thousand Mtoe - concentrated in the United Kingdom and the Netherlands. At current rates of production the reserve/production ratio is about 21 years. Future gas deposits in the Community that will be developed are likely to be smaller and more expensive to develop than those in the past.

As gas demand started to grow strongly in the 1970's, so increasing reliance began to be placed on gas imports. Indeed the European Community will need gas imports for the foreseeable future. About 1/3 of our gas supplies are imported - the main external suppliers of gas being Norway, Algeria and the USSR - three countries which possess nearly 50% of the world's proven gas reserves (see Table 4). The total value of gas trade alone in the Community (including intra-Community trade) is $20 billion a year. Gas in Europe, then, is big business.

Gas demand in the European Community in the 1980's has had a bumpy ride. From 1980 to 1982 gas demand fell in line with overall energy demand as Europe suffered its worst industrial recession since the 1930's. Since then it has grown by 15 % (a slightly higher rate than for overall energy demand) as the European economies have swung slowly out of recession. In the eighties oil demand has fallen by 13% and coal demand has been flat - but the big winner has been nuclear energy - increasing by over 200%.

TABLE 2

Primary Energy Demand Trends in the European Community (EEC-10) 1980, 1982-1986

	1980	1982	1983	1984	1985	1986*
Total energy consumption	946	886	887	912	945	972
of which:						
Oil	494	430	416	424[1]	415	429
Solid fuels	223	217	213	201	218	214
Nuclear	43	64	76	96	115	131
Natural gas	169	158	165	175	181	182
Others	17	17	17	16	16	16

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[1] Affected by UK miners' dispute

* Forecast: Energy Europe N° 5, August 1986

Source: Statistical Office of the European Community

At the political level, the European Community is trying to finalize its 1995 energy objectives. The 1995 objective for natural gas being to maintain its market share accompanied by wording emphasizing the need for a stable and diversifed supply and, if necessary, increased exploration expenditure to find new fields in the Community.

The structure of the natural gas industry is very different in Europe compared to the United States and Canada. The industry is dominated by large gas companies (e.g. British Gas, Ruhrgas, Gaz de France, SNAM, Gasunie) some of whom are public companies and have exclusive rights to buy and market natural gas in their respective countries. As a result there has been considerable Government regulation of the industry in many countries. The trunk pipelines are owned by few companies - usually the ones that purchase and market the gas.

What has happened to gas in 1986?

3. Short-Term Gas Market Developments - 1986/7

Energy prices have plummeted this year in Europe. The dollar cost of imported crude oil into the European Community compared to 1985 had fallen by more than 60% by mid-year 1986. As well, the European currencies have revalued against the $US (see Graph 1) compounding the fall in the dollar price. Today's oil price of around $14/barrel represents an average fall in price of 60% compared to 1985. Downward movements in oil prices of this magnitude are unprecedented in recent history. Rotterdam spot prices of petroleum products have also fallen sharply - some by as much as for crude oil. Although only three Community governments have left their consumer oil taxation unchanged, tax inclusive consumer oil prices in Europe have fallen substantially.

As for gas, the first point to make is that, in Europe, the price of natural gas imports is now generally indexed (with around 6-9 month lags) on the price of fuels that gas competes with in end-use markets (mainly residual fuel oil and gasoil). This has meant that in a period of falling oil price gas prices have been temporarily uncompetitive in many European markets, because imported natural gas and wholesale prices have not fallen as fast as oil prices, as can be seen in Graph 2. But, provided oil prices do not fall again, the competitive position of gas will improve over the next 2-3 quarters.

The vulnerable part of the natural gas market has been industrial interruptible business (approximately 20% of total gas sales). There, by definition, the industrial unit has a choice of fuels - and in many European markets they have used it to the detriment of gas in the first half of 1986. This is not to say that gas suppliers and distribution companies have stood by and let bargain basement fuel oil sweep away its industrial markets. Far from it - indeed in many countries industrial gas prices have responded flexibly and quickly downwards - even anticipating future oil price falls. In addition some suppliers have helped matters by acting flexibly. So in some countries distributors have taken short-term losses to protect their market share. But others have been more constrained by cash flow and borrowing difficulties and have had to yield, temporarily, to fuel oil. Indeed - netting out the effects of the United Kingdom miners' strike - European fuel oil demand increased in the first half of 1986: a trend that was unthinkable 9 months ago. Against coal, however, the reverse is true. The price advantage (at the burner tip) that coal enjoyed against oil and gas in previous years has been completely eroded this year.

"Firm" industrial gas demand has been less affected in Europe, and domestic sales (the premium market) have been buoyant due to the cold winter and the increasing client base. Gas prices in the captive household markets which have been traditionally "sticky", are now beginning to edge downwards. But price reductions in this sector have been far less than the price adjustments in the industrial sector.

The following table shows how gas demand has evolved in the first half of 1986 in the main European markets, by sector:

TABLE 3

Estimated European Gas Demand

(first half 1986/5) % change

	Industry	Residential	Total
FR Germany			-2%
France	-6%	+7%	+2%
Netherlands	-5%		-2%
United Kingdom	-5%	+8%	+3.0%
EUROPEAN COMMUNITY	.	.	+1.5%

. = not available

The short-term prospects for European gas demand in 1986, therefore, are rather flat. Apart from the difficulties in gas pricing, the economic situation in Europe has not picked up as quickly as expected following the fall in oil prices and industrial output in some key gas consuming industries is also likely to slow in 1986.

Overall gas demand in the European Community is forecast to increase by no more than 1-2% in 1986 - a much slower rate of growth than in the previous 3 years. But, depending on the economic outcome and the direction of oil prices, 1987 should be a better year for gas.

4. Can some conclusions be drawn from this period of rapidly falling energy prices?

Firstly, because of the way many gas supply contracts are now specified - an unstable, volatile and falling oil price environment will tend to narrow the competitive advantage that gas has traditionally maintained against oil. The competitive position of natural gas should nevertherless start to improve from the fourth quarter of 1986 onwards. In the past gas penetration has tended to occur in periods of rising oil prices when the lagging supply price mechanisms help natural gas.

Secondly, the actual switching between fuel oil and gas in industry has been higher than expected in Europe. In the domestic market, the rate at which existing space heating installations are retrofitted has slowed down.

Thirdly, a possible consequence of the present energy price situation in Europe could be to encourage more dual-fired flexibility in the future as industries and even in the future households perceive the necessity of flexible fuel use to counteract uncertain and unpredictable short-term energy price movements.

Fourthly, that unexpected oil price movements of the magnitude we have witnessed this year have profound macro-economic and political consequences. Government budgets can be seriously dented, trading relationships strained and the planning environment upset. For example, the shortfall in gas revenues for the Netherlands Government in 1986 is around 30% alone. The British Government now has a more difficult environment in which to float the privatisation of the British Gas Corporation on the world's financial markets in October this year. For the Soviet Union - although gas only earns one-quarter of the hard currency that oil yields - a sudden 40% drop in overall hard currency earnings due to falling energy prices from energy exports must have important geopolitical consequences. And of course there are the oil producing countries themselves - some of whom have lost up to 50% of their export income in the first half of 1986.

This is the law of the market and I am not arguing against it - but I am saying that there is still the case to be made that lurches in energy prices of this magnitude (whether upwards or downwards) and the great uncertainty that results, help improve the world's economic or energy situation in the medium or long run. I fear the reverse could be true.

Fifthly, the rapidity and size of the cutbacks in energy investment. Here in Calgary you are fully aware of this. I understand that as many 40,000 jobs have been lost in Western Canada this year due to falling energy prices. But the economic downturn in Aberdeen in Scotland for example is also very severe. We have not escaped the axe in Europe. For example, very recently Britoil, one of the UK's leading independent oil companies made 950 people redundant from its payroll of 2,500. Vital exploration, drilling and development expenditure on new oil and gas fields has been cut back in Europe - estimates are as high as 30-40% of planned 1986 budgets. So far the energy effects have been limited in the short-term - but there is a danger that gas fields that Europe will need in the 1990s may be postponed or not developed at all if low prices remain. It is worth noting that two countries in particular, Italy and the United Kingdom, are putting a great deal of reliance on developing indigenous production to cover gas supplies in the 1990's.

5. Longer-Term Issues for Gas

Let me begin here with the news about the Norwegian gas field Troll.... and a quotation:

> "Troll. This enchanting Gremlins-style fantasy-comedy, about mini-monsters usurping an apartment house, has a witty script and five-star special effects. It spearheads a season called "Empire of the Senseless" and is devoted to low-budget, high-resource fantasy."

This, as you have guessed, has nothing to do with the Troll gas field in Norway - it is in fact the London Financial Times arts correspondent's description of a new film called "Troll" just released in London!

Nevertheless, some of the flowery language could be used to describe the Troll gas field.

"Mini-monster" - the size of the Troll field is in the same ballpark as the Groningen field in the Netherlands - with reserves put at around 1,300 billion m^3 - sufficient to supply 10-15% of projected west European gas demand for 40 years. The Troll deal (including Sleipner east) is for 500 billion m^3 of the 1,500 bcm Troll/Sleipner reserves.

"Five-star special effects" - the Troll/Sleipner development transforms the European gas supply position in the 1990's and into the 21st century. Prior to the signing of the Heads of Agreement deal, the European Community countries were short of approximately 20 Mtoe of contracted supply in the 1990's. The Troll deal (if ratified by the Norwegian Parliament and endorsed by the European consortium's governments) would fit the bill perfectly (see Graph 3). The contract also allows buyers to increase supplies beyond 2000 up to 80% of Troll's plateau production (i.e. for an extra 16 bcm/year). Deliveries are scheduled to begin in 1993 with initial supplies coming from the Sleipner east field, Troll being linked up in the second half of the 1990s (see Graph 4). By the year 2000, 20 billion m^3 of gas would be delivered per year to the European buyers.

With the Troll agreement in place, the supply shares in the European Community's gas market could work out as follows:

TABLE 4

Share of total gas supply in European Community

		1985	1990	2000
Indigenous production		67.2%	60%	63%
Imports		32.8%	40%	37%
of which:	Norway	11.8%	12%	10%
	USSR	11.2%	16%	16%
	Algeria	9.2%	12%	11%
	Libya	0.5%	-	-

Source: Member States of the European Community

"Low-budget" - Unfortunately the opposite is true. The development costs (including pipelines) of Sleipner and Troll are large and front-end loaded - upwards of $10 billion (1986) inclusive of transportation pipelines. The Norwegian Government itself has a large share in the investment expenditure.

The press reports that Troll prices will be similar to Dutch border prices which in turn are linked to the price of competing oil products. There is considerable flexibility in the contract including regular reviews of the pricing mechanisms. The economics of Troll, however, could start to look difficult if oil prices do not substantially increase from today's levels.

The official timing is that it is hoped the Troll deal will be ratified by the Storting (the Norwegian parliament) by 1 January 1987 following final agreement by the buyers expected by mid-October 1986 at the latest. The financing package will then be arranged. However, this is a tight timetable as the producers and the Norwegian Government are still locked in discussions on such matters as the taxation regime, the length of the Troll concession (currently 2021) and the "sliding scale" which gives the possibility of increased Norwegian State participation in the future.

The Troll deal is therefore a crucial gas deal in Europe. It will guarantee the Norwegians a substantial presence in Europe's gas markets well into the 21st century. It increases the supply options in Europe, and lessens the dependence on Algerian and Russian supply. The main option at the moment is that the gas will be transported by pipeline to Zeebrugge in Belgium and Emden in FR Germany. But eventually the gas could also be landed in the UK as well (Bacton, or making use of the Frigg lines?). These offer interesting possibilities. Furthermore, because the deposit is so large there is no constraint on the seller's side to seeking additional markets - in particular to the United Kingdom, which last year vetoed an original deal on Sleipner to replace Norwegian Frigg gas for the early 1990s and to new markets further afield to Spain, Portugal, Switzerland, Italy, Austria and Sweden.

As a result of the Troll deal have the Russians lost out? It is unlikely that Russian gas would have supplied the remaining gas Europe needed in the 1990s. But with large gas reserves and an estimated 16% of overall Community gas supplies in the 1990s they are still well placed for the next century. With the flexibility in the existing contracts, the European Community countries now have adequate contracted imported gas supply into the 21st century with the only major doubt remaining being whether the United Kingdom will be able to find and produce enough gas in the 1990's to avoid further imports. It boils down to this - there is basically little room left for substantial new import deals for a minimum of 15 years to come.

The international energy implications of this deal are surely that it will be even more difficult for oil to make a comeback in Europe - even if oil prices are low. Coal, too, could also have more difficulties than before against gas.

6. **What are the major uncertainties that could upset this picture of equilibrium between gas supply and demand for the rest of this century?**

The first uncertainty could relate to the demand projections themselves. Government projections of gas demand have been scaled down over the last few years. According to the European governments' latest projections (Graph 5), European gas demand is hardly expected to grow at all in the 1990's. What is the thinking behind this?

1) The expected slowdown in the rate of growth of the population in the 1990's compared to the 1970's and early 1980's - particularly in the mature northern European gas consuming countries (Germany, Netherlands, France and the United Kingdom);

2) The continuation of energy efficiency improvements, which are inevitable as the capital stock turns over and could go on irrespective, to a large extent, of the evolution of oil prices. The introduction of new gas technologies (gas condensing boilers) could also play a part. Tighter building standards and insulation norms could well help to substantially offset the projected increase in gas demand in the residential sector. As for industry - the chemical industry alone consumes over 40% of European industrial gas demand. The chemical industry has a good record of energy saving - and the European chemical industry will continue to be under severe competitive pressure as new Middle East producers of base chemicals come on stream. It will need to go on saving energy;

3) De-industrialization in Europe continues. For example, in 1974 the Community produced 155 million tonnes of crude steel. Today the figure is unlikely to reach 115 million tonnes. Whilst the service sector booms, the traditional energy-intensive industries are tending to stagnate or decline;

4) The outlook for long-term economic growth. The economic growth rate in the Community has failed to reach 3% per year in any year since 1979. Even this year when many indicators appeared at first

to be pointing in a favourable direction - only 2.7% economic growth is forecast - with next year's forecast at only 2.8%. The Commission of the European Communities has adopted a medium-term growth strategy of 3.5%/year but this could turn out to be optimistic.

5) There is near saturation in some residential markets (UK, NL).

All these reasons, then, argue strongly for rather moderate gas growth in the medium-term.

On the other side of the coin, it should not be forgotten that there will be new growth markets for gas - particularly in the south of Europe. Even in FR Germany 2 million new clients are expected in the residential sector in the 1990's. My view is that these latest Member State forecasts do seem on the low side.

Our own work in the Commission, however, suggests that natural gas demand will increase in the 1990's (a view shared by the IEA). Indeed our recent analysis suggests that should oil prices remain low then natural gas demand in 1990 could well be up to 7% higher than previously anticipated (see Table 5). Overall energy demand will also be higher. In a low oil price scenario, it is argued, natural gas could make inroads into coal's markets. Indeed the great advantages of natural gas are its characteristics of cleanliness and controllability which give it specific advantages in certain operations. Add in low prices and this could help industrial gas demand to expand in the under-boiler market. With buoyant economic growth, gas penentration could increase.

If oil prices turn out to be high in the 1990's gas could also be well placed. Gas prices would be lagging oil prices (and therefore undercutting them). And if oil prices surged to new heights - the likelihood of gas prices decoupling from oil prices may increase. In any case, gas penetration would still increase.

The Commission's own forecasts are as follows:

TABLE 5

European Community Energy Forecasts[1]

	1985	Energy[2] 2000 study 1990	Energy[2] 2000 study 2000	$15 oil price[3] 1990
Total Energy Consumption	945	1006	1107	1005 - 1040
of which :				
Oil	415	413	410	438 - 466
Solid fuels	218	242	264	212 - 223
Nuclear	115	145	215	140
Natural gas	181	190	196	190 - 203
Others	16	16	21	15

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[1] Published work of the Commission of the European Communities.

[2] Reference projection - (crude oil import price $27 (1983) in 1990 and $35 (1983) in 2000; GDP growth 2.4%/year 1983-1990, 2.8% 1990-2000).

[3] "Lower Oil Prices: - The Implications for the Community Energy Balance in 1990" (assumes $15 oil to 1990).

But even if natural gas demand was higher than our governments believe, the flexibility in the supply contracts are still adequate to cover this demand. But there is one sector which we have failed to mention so far, which could, conceivably, swing European gas demand upwards by much more than expected in the long-term - namely in the power generation sector. Here, of course, we come to the aftermath of Chernobyl.

7. The influence of Chernobyl and other environmental issues on future gas demand in the power generation sector

It would be quite wrong to suggest to this conference that in Europe today that we can already see a clear picture emerging of the consequences of this disastrous nuclear accident. It is early days. But one thing is for sure - nuclear energy has been dealt a body blow in Europe. Public opinion has been alarmed at the magnitude of the damage, the number of casualties, as well as the scale of the radioactive pollution - which has affected to varying degrees most European countries. Having taken place in Europe and because it was more serious, the Chernobyl accident will have a much greater effect in Europe than the accident at Three Mile Island.

Nuclear energy in Europe has played an important part in improving energy security. By 1990 we had been expecting nuclear to be providing 40% of our inputs for electricity generation. But this accident has raised a great number of questions and we cannot be sure what will happen to nuclear programmes in the Community now - especially in the long term. Our current feeling is that most of the nuclear plants either operating or under construction will go on as heretofore. But governments will find it more difficult to embark on ordering new nuclear power stations.

But as a result of the accident some important political parties have been shifting ground on the nuclear issue (the SPD in Germany, the Italian socialists, the Labour party in Britain, and decisions on the Netherlands nuclear programme have been delayed again). There are elections next year in FR Germany, and possibly in the United Kingdom, and nuclear is going to be one of the key issues.

Coal, too, is under pressure because of "acid rain". Stricter environmental standards are in the process of negotiation in the European Community for large combustion plants to reduce SO_2 and NO_x emissions. The public, again, is alarmed at the damage due to acid rain with environmentalists in the Scandinavian countries and the FR Germany being particularly vociferous. Eventually Community governments will agree to stricter emission standards in one form or other - and these will inevitably put up the cost of coal-generated electricity. And oil? Oil will not escape these new environmental regulations either - and so the costs of oil-fired generation will also increase. Under 0.65%S fuel oil will be required in the future for oil use for power generation and in industry.

So, taking all this into account, could gas benefit?

Gas consumption in European Community power stations has fallen by a third in the last 10 years. There are several reasons for this - in particular the start up of the European nuclear power programme which began to displace both oil and gas used for baseload electricity generation. (Incidentally, nuclear energy now covers over 35% of the Community's electricity supply and as much as 65% in France). The costs of gas-fired generation were also unattractive as oil prices increased. Also as the Community's gas grid developed so supplies were diverted away from the power sector to new premium markets. Lastly, there are the Community's own rules introduced in the '70s which aim to limit the use of natural gas in power stations - reserving gas for more "noble" uses.

On this score, who can tell now what the future may hold. But, unlike before, it is possible to see conditions in which natural gas demand could increase in power stations. The environmental advantages, that gas has, and a slowdown or shutdown of some nuclear plants in the political fall-out from Chernobyl could well be factors that could lead to natural gas increasing its share in the European energy balance in the future. As an example a recent study by the Prognos institute in Basel, Switzerland, suggested that were nuclear plants closed down in FR Germany in the 1990's - gas consumption in power stations in that country would have to triple. Another example is that as a result of Chernobyl the Italian government is completely reviewing its energy policy later on this year - and extra hydrocarbon burn in power stations cannot be excluded.

8. Are there any other ways in which natural gas could substantially increase its market share in the long term?

Here I would like to mention two possible changes that I have already hinted at that could give rise to this - the first being organisational changes in the European gas industry, which is not unrelated to the second possibility of changes in gas pricing arrangements - for example, a break in the traditional link between oil and gas prices.

Organisational change

Traditionally the supply of natural gas has been based on long-term contracts of around 20-25 years between buyers and producers. The renegotiated Dutch export contracts, for example, cover the period to the year 2010, Troll contracts to 2020. In the United States a more dynamic and flexible market has evolved where gas is frequently transported by pipeline companies on behalf of third parties. I believe the spot market in the US now accounts for 17% or more of total natural gas sales in the US. But in Europe there are a limited number of buyers of gas and sellers - and this situation looks likely to continue. There are some minor changes afoot that could encourage more flexible marketing in the future (the introduction of common carriage provisions in the UK) but changes of this type are still comparatively rare. The amortization of large parts of the Community's gas transportation infrastructure will help to reduce transportation costs in the coming years - and this could also be a pointer to change.

As for pricing - could oil and gas prices decouple in the foreseeable future?

The Chairman of Ruhrgas, the powerful Germany gas company, has strong views on the matter. In a speech to the Energy Institute of Cologne University in April 1986 he said "....It is only possible to forgo formal price links (between oil and gas) in the case of short-term supply agreements....but if the sides have to spread the cost of investment for specific supply projects over several years, which is the normal procedure (in Europe) - it is impossible to formulate such a supply agreement over a long time period with a price that has become inappropriate." (i.e. a gas price linked to oil prices).

There are two key points here. Firstly, oil is the price leader, the marginal fuel and the fuel gas most competes with. So there is a certain convenience in ensuring that gas prices are linked to oil prices in one way or other. Secondly, the small number of sellers and (largely monopolistic) buying utilities in Europe and the fact they are linked through long-term supply deals and by a degree of common ownership tending to influence price arrangements. But there is an alternative view which says that gas, like most other goods and services, should be priced according to its own costs of production, irrespective of the price of oil.

The dominant position of national gas companies and the gas producers would seem to rule out substantial changes in the link between oil and gas prices in the near term. Of course there have been changes in gas pricing in Europe. For example, the Norwegians have shifted ground on the pricing of Troll by dropping the idea of a security premium for Norwegian gas supply and the Algerians, for the time being at least, have backed off insisting that their export prices be linked to official crude prices. But we are still a long way off from developing a substantial competitive market for gas.

9. Gas security issues in Europe

Gas security issues have been at the forefront of political debate in Europe for several years. So before entering this minefield, I should define my terms. The interest in the gas security issue in the European Community stems from concern about the possibility of over-dependence on external sources of gas supply particularly the USSR and the possibilities of a major interrruption of supply from one or more supply sources.

I have already spoken about the supply structure in Europe - and the importance of the Troll deal to diversifying it in the 1990's and beyond. The level of non-OECD gas imports into the European Community are now expected to remain stable at around 27% between 1990 and 2000.

Recent studies carried out by the Commission, with experts from our Member States, suggest that existing and planned security measures should be sufficient to deal effectively with an interruption of supply from any individual import source for a considerable length of time. The security situation has much improved in the Community since 1982 when a similar study was undertaken. The main reason for this is extra storage capacity. Details are due to be published very shortly.

But we must beware of complacency - there is always room for improvement. Further integration of the Community's gas grid particularly westwards from the continent of Europe to the United Kingdom and Ireland and southwards to Spain, Portugal and Greece could clearly play an important rôle in boosting security. If such gas grid developments are to take place, however, they must be decided on commercial terms. Is it possible that the Norwegians could provide a substantial impetus to the development of the Community's gas grid as they seek their new markets as the Troll package comes on stream? Of course the development of the grid would be welcomed in the European Community as a future step along the road for constructing a common market in natural gas.

Ladies and Gentlemen, let me conclude this review of gas developments in Europe by saying that 1986 has been an important year for energy in Europe. Of course, if some of the pointers I have given you today about the gas markets in Europe should turn out to be correct - I will be more than willing to come back, in future years, to support your excellent conference! Thankyou.

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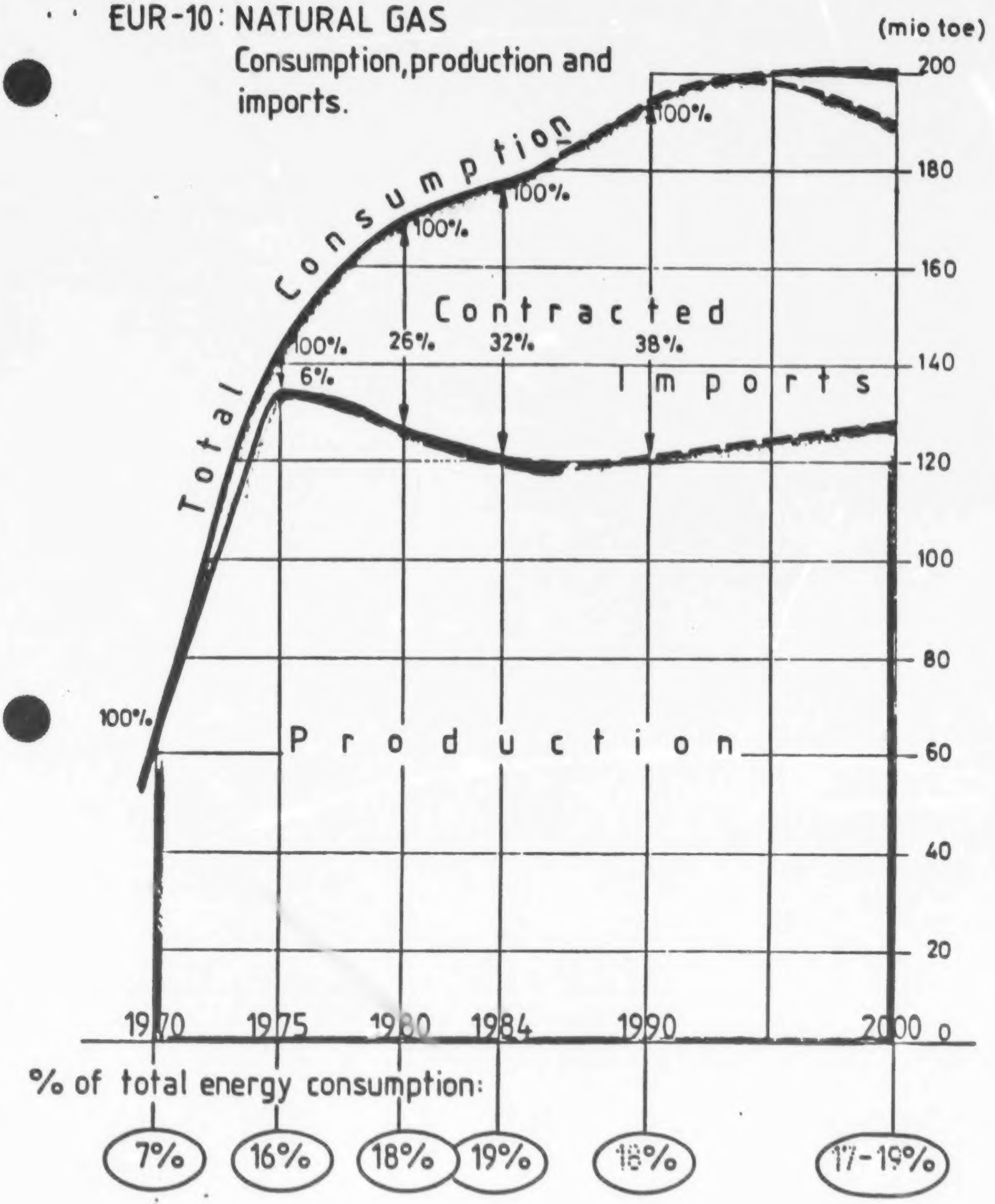
Graph 2

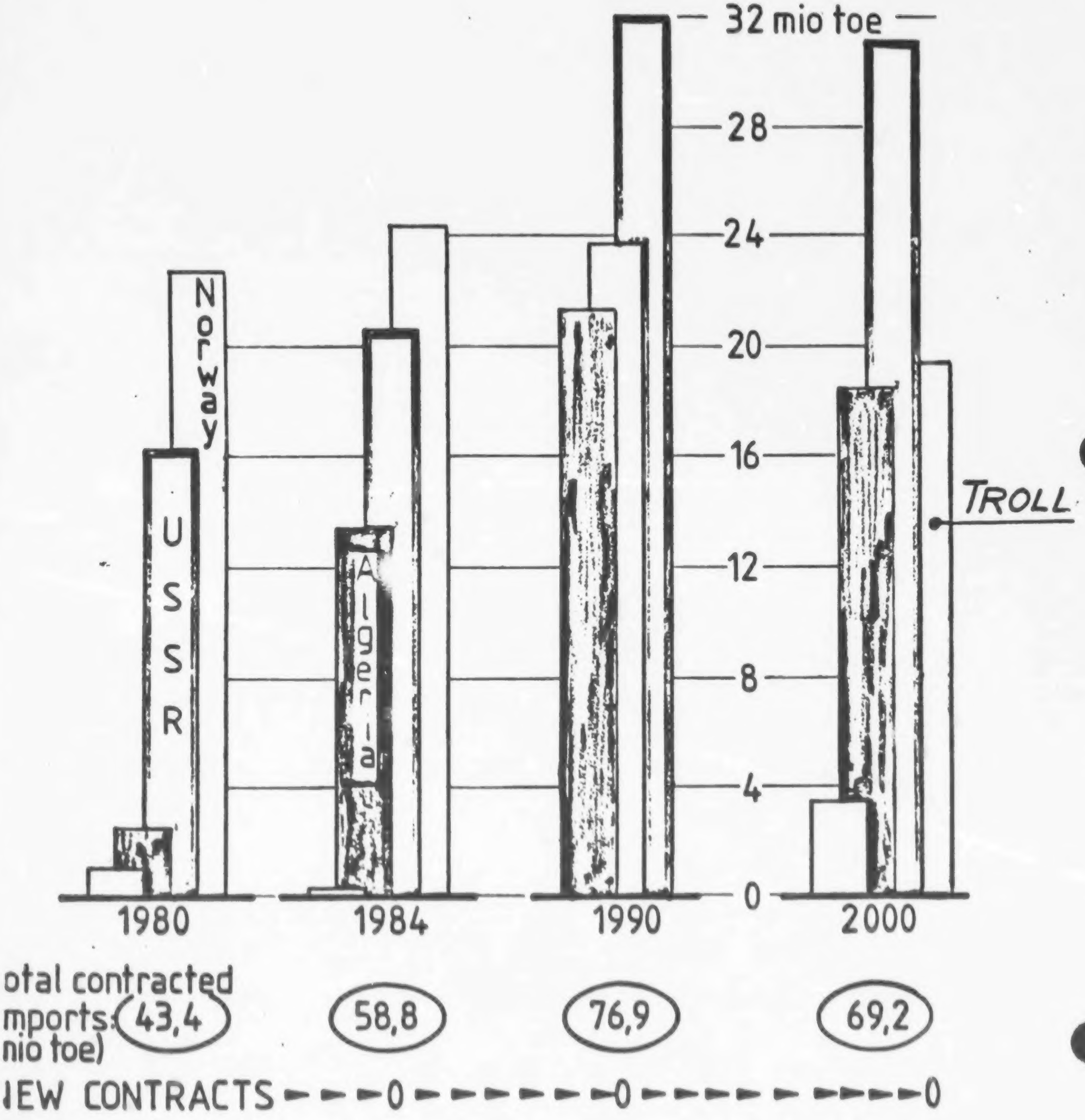
EUR-10: NATURAL GAS
Consumption, production and imports.



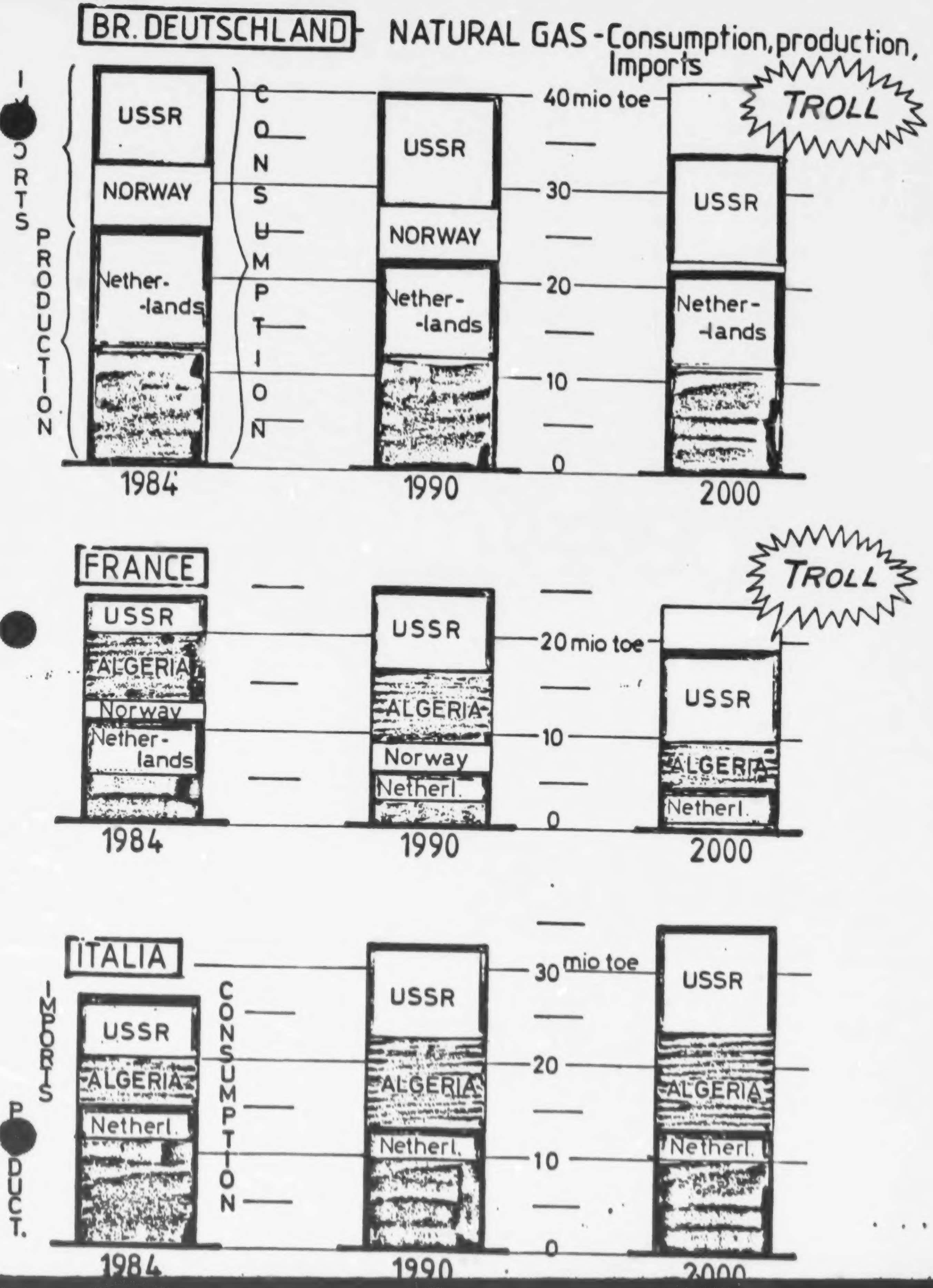
Graph 1

EUR-10: NATURAL GAS

Imports from third countries



Graph 3


BR. DEUTSCHLAND - NATURAL GAS - Consumption, production, Imports
IMPORTS
PRODUCTION
CONSUMPTION
USSR
NORWAY
Nether- -lands
40 mio toe
30
20
10
0
TROLL
1984
1990
2000
FRANCE
USSR
ALGERIA
Norway
Nether- lands
Netherl.
20 mio toe
10
0
TROLL
1984
1990
2000
ITALIA
IMPORTS
PRODUCT.
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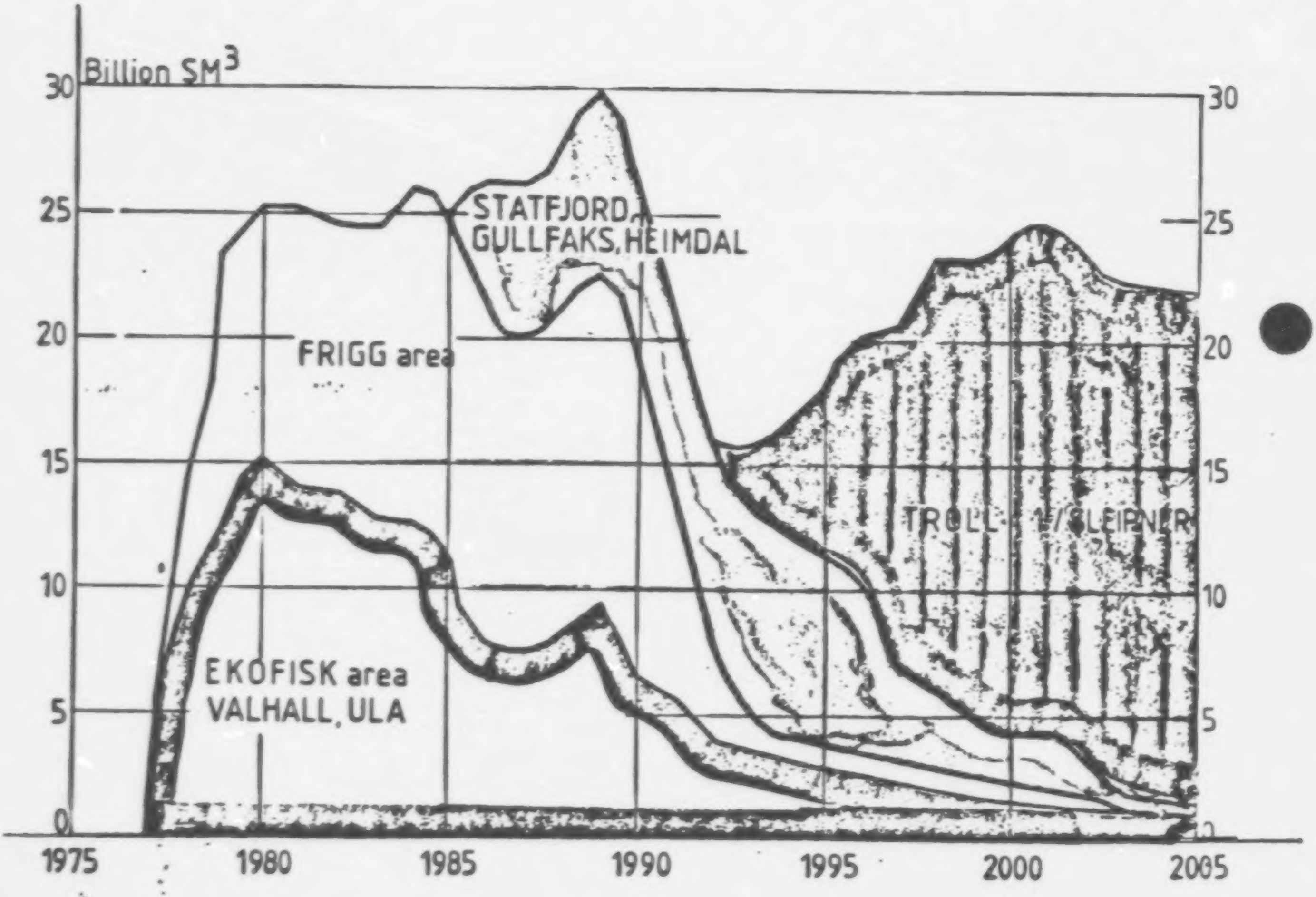
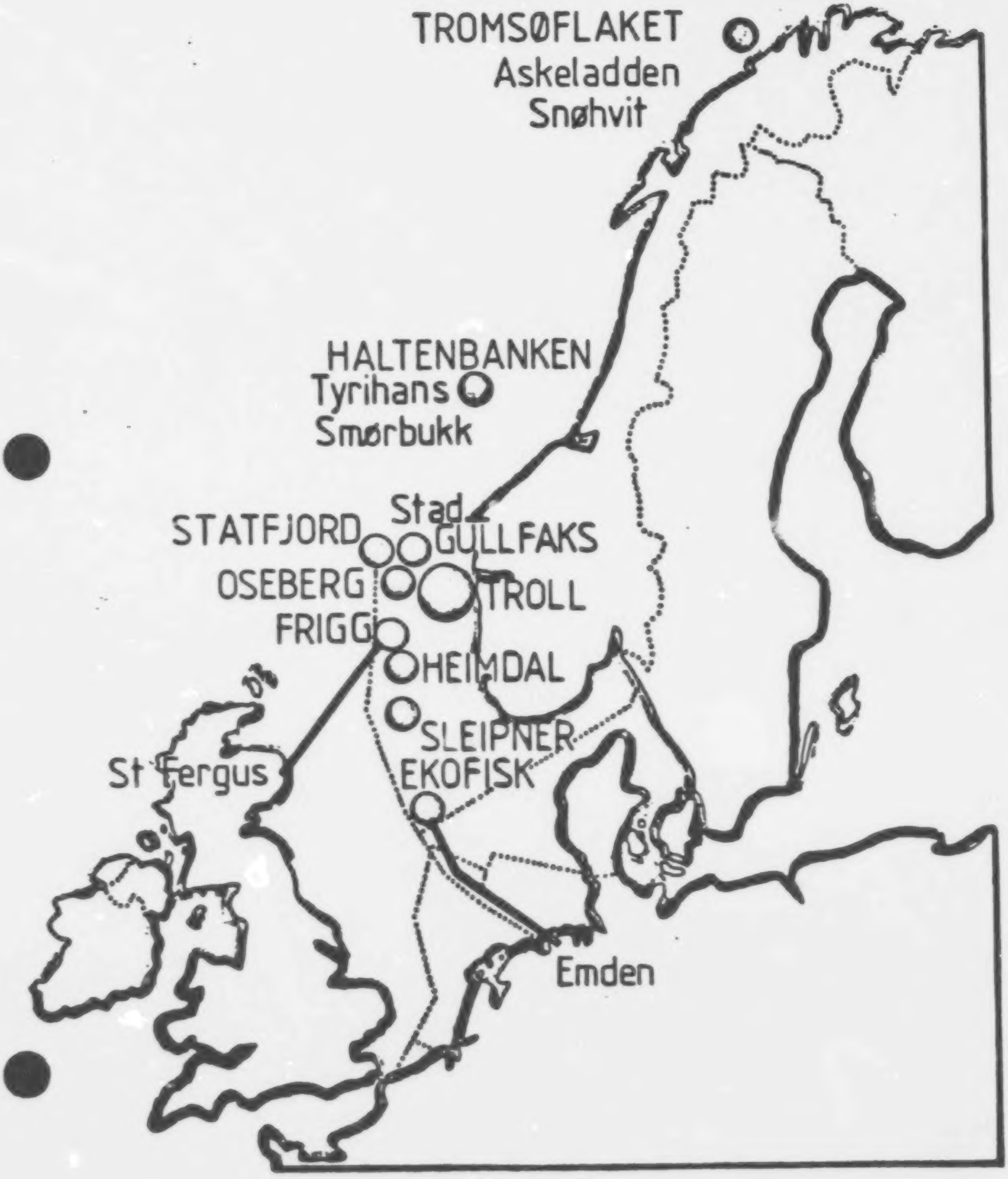
NORWAY

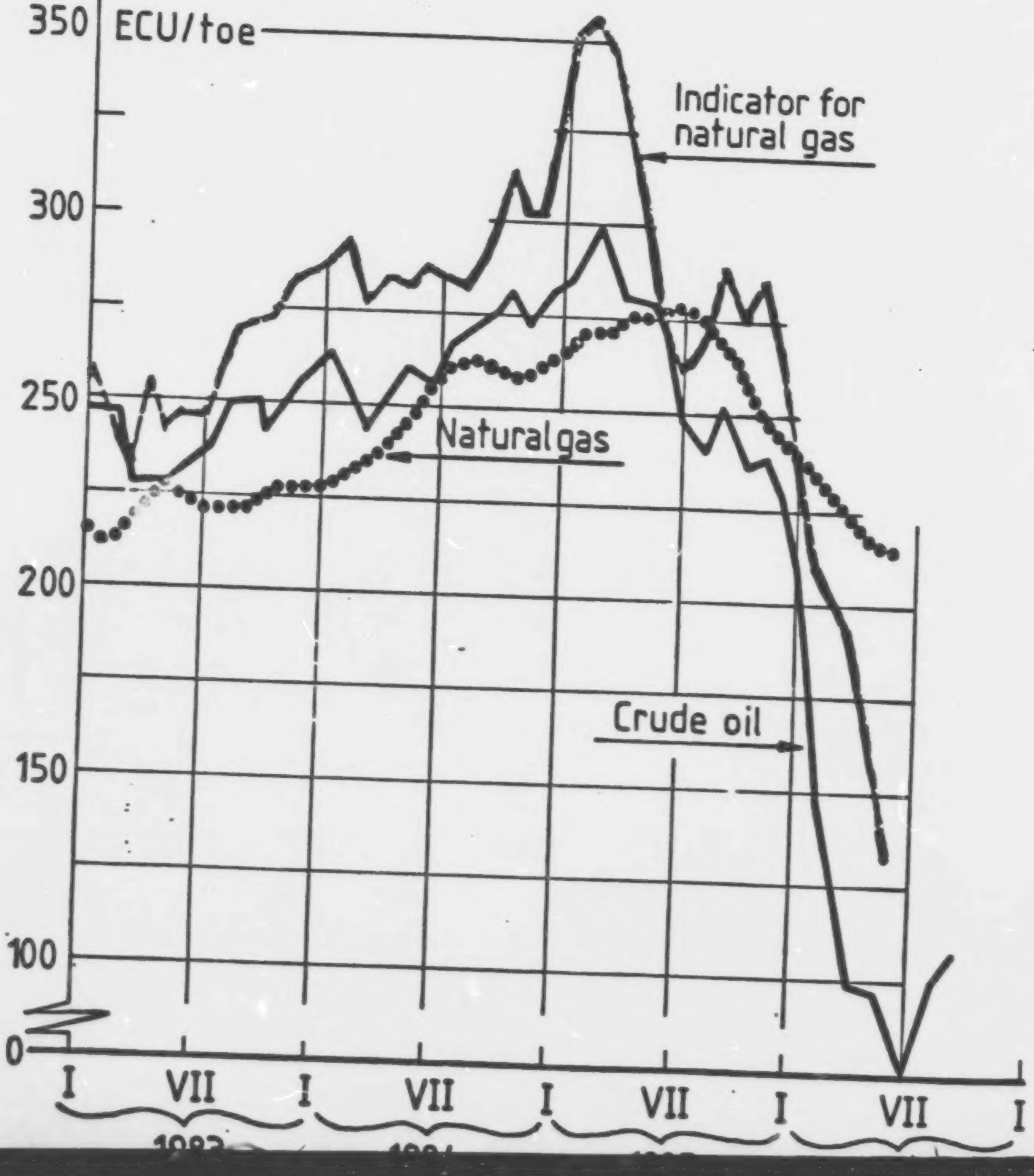
FORECASTS OF GAS PRODUCTION



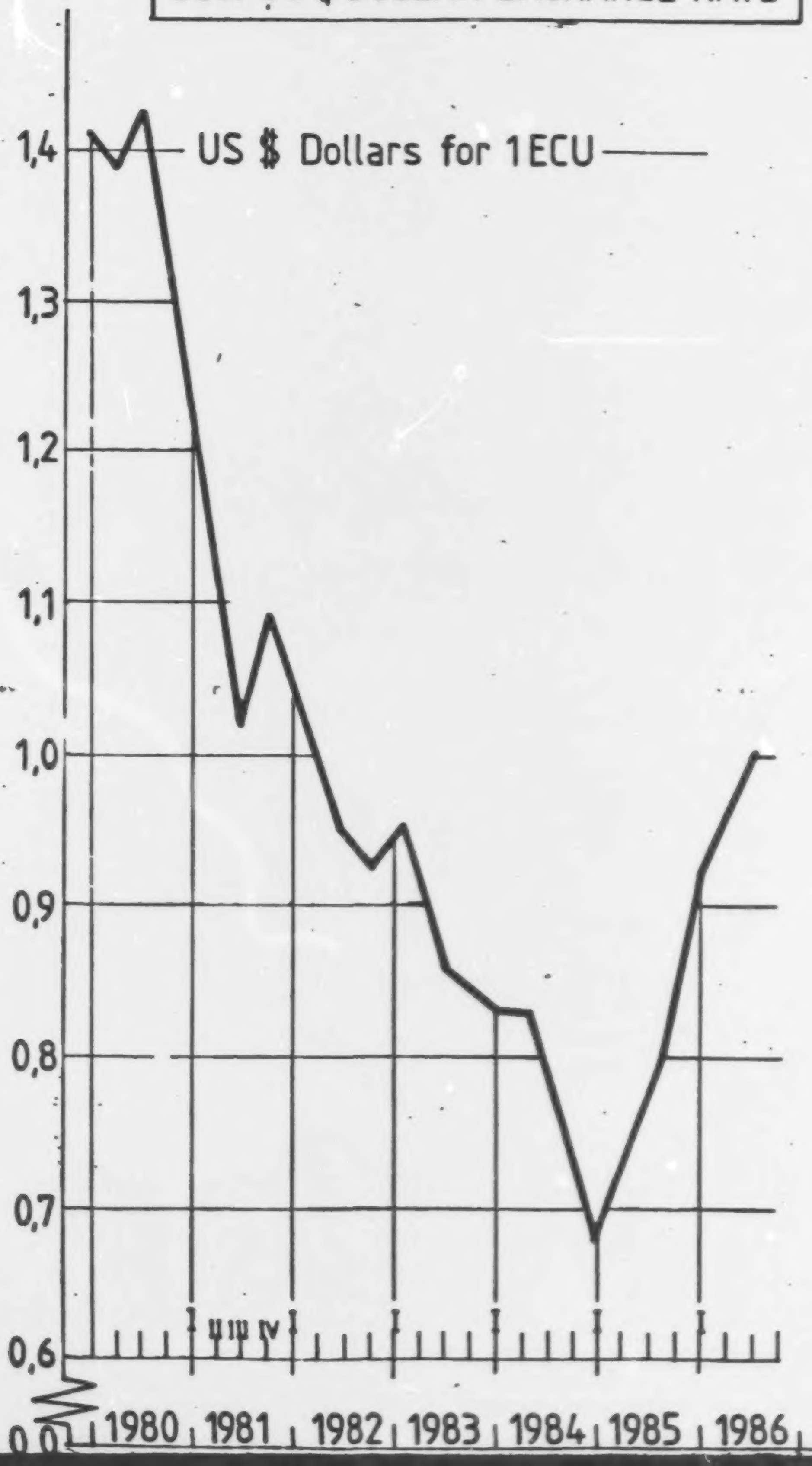
NORWEGIAN GAS PROVINCES 1985


TROMSØFLAKET
Askeladden
Snøhvit
HALTENBANKEN
Tyrihans
Smørbukk
Stad
STATFJORD
GULLFAKS
OSEBERG
TROLL
FRIGG
HEIMDAL
SLEIPNER
EKOFISK
St Fergus
Emden

EUR-12: AVERAGE CRUDE OIL AND NATURAL GAS IMPORT PRICES AND FORWARD INDICATOR FOR IMPORTED NATURAL GAS (50% RFO, 50% GDO ex tax consumer price in BRD)



ECU/ US $ DOLLAR EXCHANGE RATE



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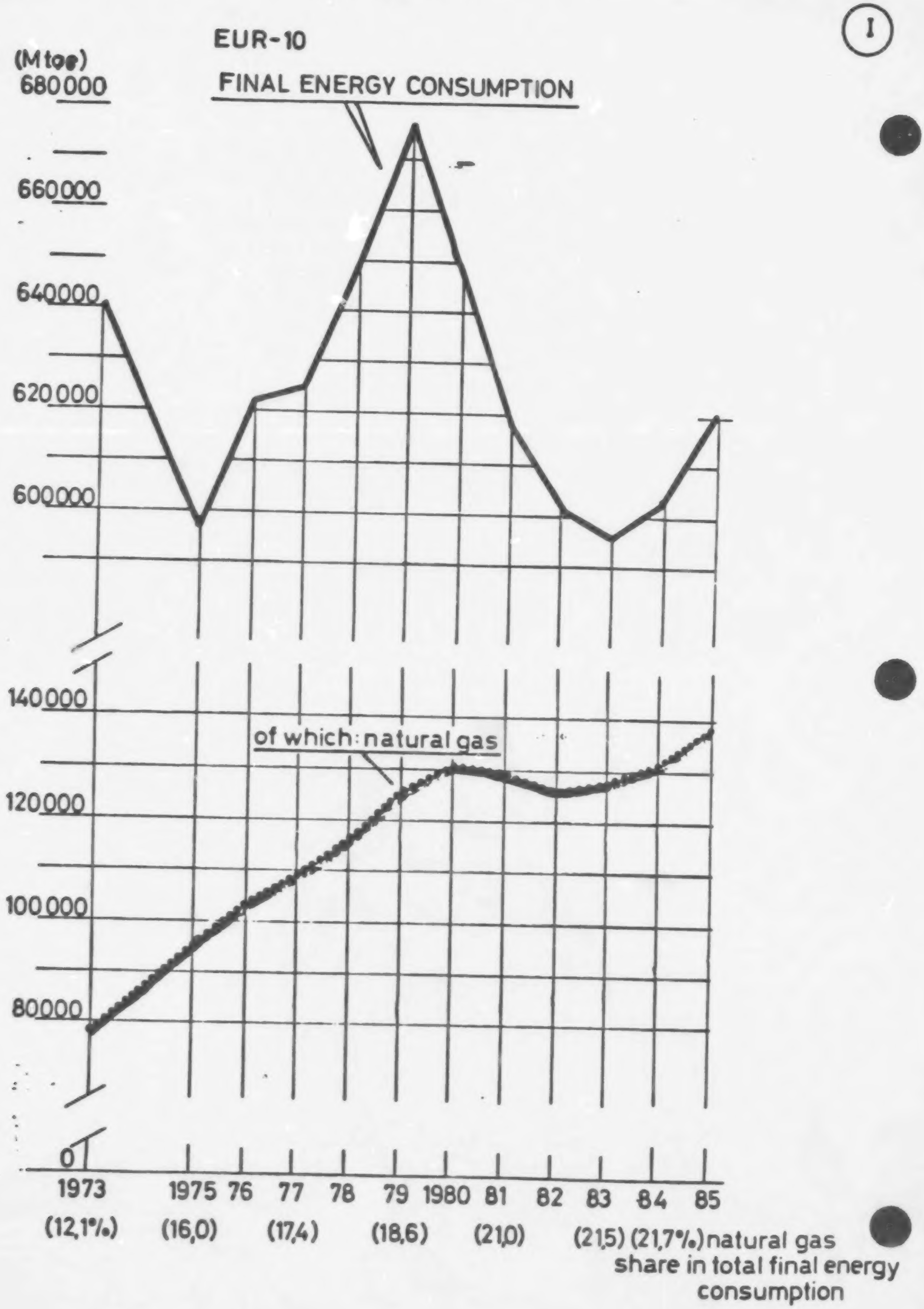
EUR-10
(M toe)
FINAL ENERGY CONSUMPTION
680000
660000
640000
620000
600000
140000
of which: natural gas
120000
100000
80000
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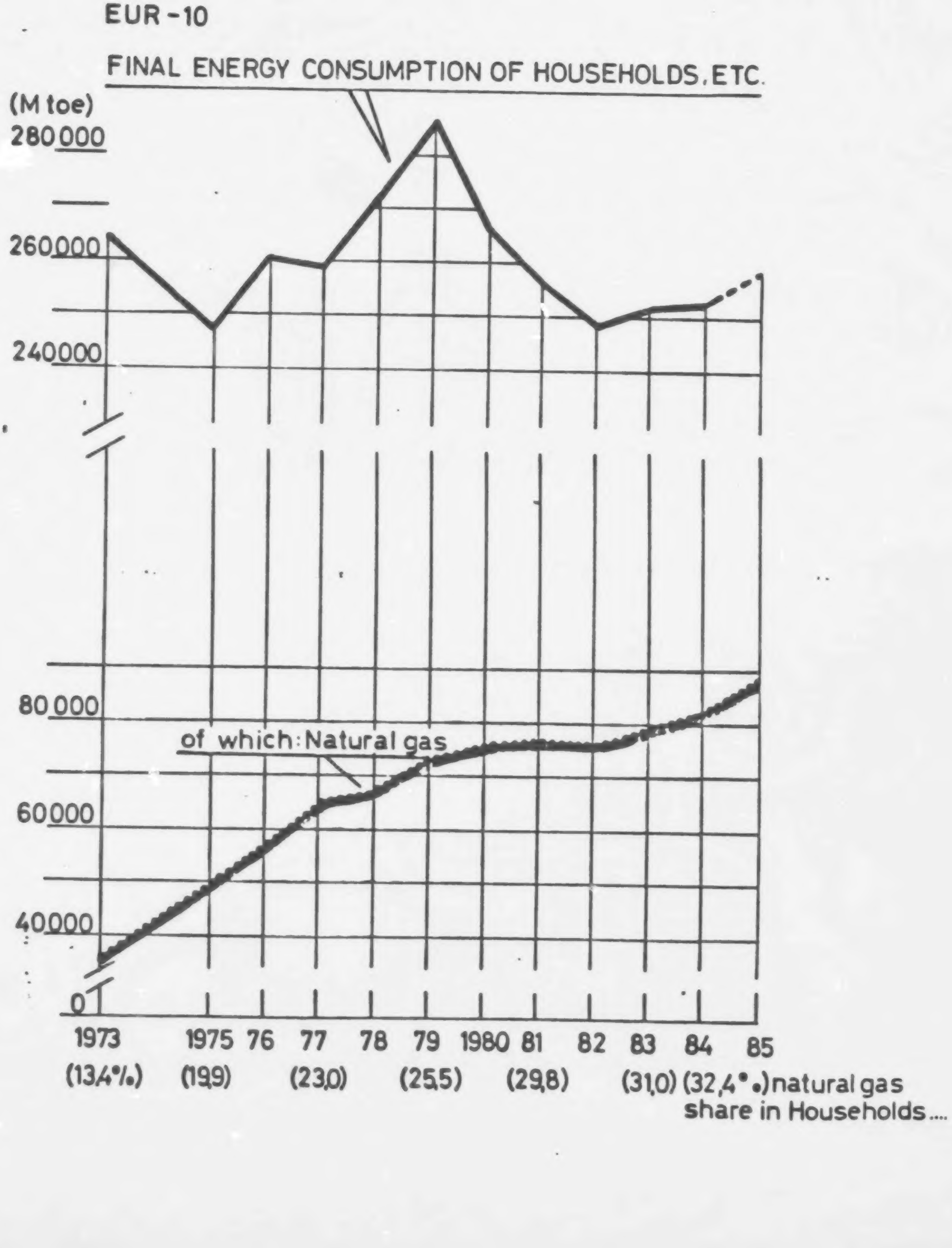
1973
1975
76
77
78
79
1980
81
82
83
84
85
(12,1%)
(16,0)
(17,4)
(18,6)
(21,0)
(21,5)
(21,7%) natural gas share in total final energy consumption


EUR - 10
FINAL ENERGY CONSUMPTION OF HOUSEHOLDS, ETC.
(M toe)
280 000
260 000
240 000
80 000
60 000
40 000
0
of which: Natural gas
1973
1975
76
77
78
79
1980
81
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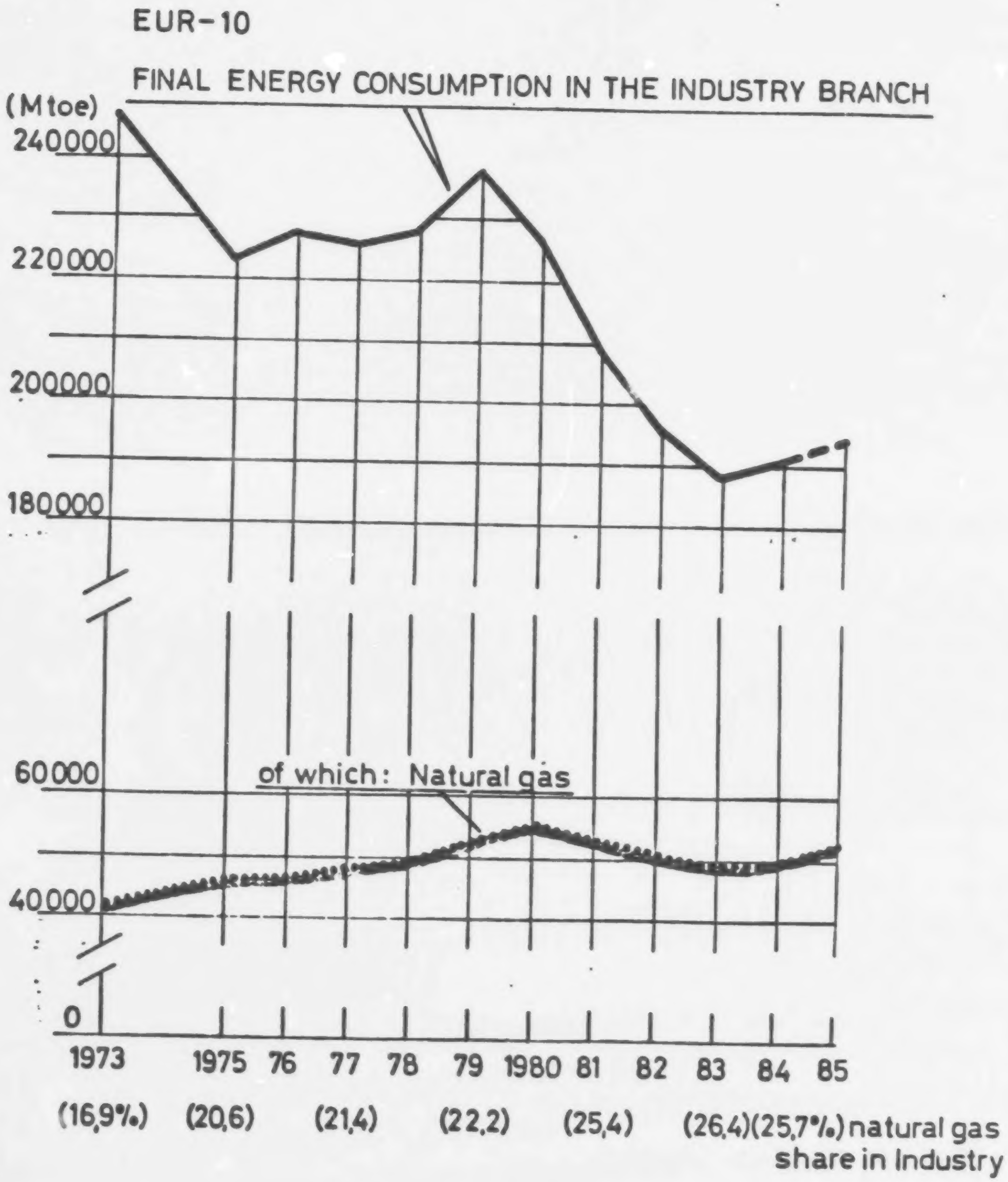
84
85
(13,4°/.)
(19,9)
(23,0)
(25,5)
(29,8)
(31,0)
(32,4°.) natural gas share in Households....


EUR-10
FINAL ENERGY CONSUMPTION IN THE INDUSTRY BRANCH
(Mtoe)
240000
220000
200000
180000
60000
of which: Natural gas
40000
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1973
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76
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78
79
1980
81
82
83
84
85
(16,9%)
(20,6)
(21,4)
(22,2)
(25,4)
(26,4)(25,7%) natural gas
share in Industry

PROSPECTS FOR INDONESIAN OIL AND GAS DEVELOPMENT AND EXPORTS

REMARKS BY:

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MINISTRY OF MINES & ENERGY
INDONESIA

THE INTERNATIONAL OIL AND GAS MARKETS CONFERENCE
CALGARY, ALBERTA
SEPTEMBER 14-16, 1986

IT GIVES ME GREAT PLEASURE TO BE HERE WITH YOU TODAY. I WOULD LIKE TO TAKE THIS OPPORTUNITY TO THANK THE SPONSORS OF THIS CONFERENCE, THE CANADIAN ENERGY RESEARCH INSTITUTE AND THE CALGARY CHAMBER OF COMMERCE, FOR INVITING ME TO SHARE MY VIEWS ON INDONESIAN OIL, ESPECIALLY ABOUT THE POSSIBLE DEVELOPMENT AND EXPORTS IN THE NEAR FUTURE. MAY I COMMEND THESE ORGANIZATIONS FOR SPONSORING THIS VERY TIMELY CONFERENCE. THE GLOBAL, REGIONAL AND NATIONAL FOCUS OF THE VARIOUS SECTIONS OF THIS CONFERENCE SHOULD BE VERY HELPFUL TO ALL OF US IN UNDERSTANDING THE INTERNATIONAL DIMENSION OF OUR INDIVIDUAL COUNTRY ACTIONS. PETROLEUM EXPLORATION, DEVELOPMENT AND SALES ARE TAKING PLACE IN A VERY COMPETITIVE WORLD, WHERE WE HAVE ALL LEARNED, IN THE PAST FEW YEARS, THAT GLOBAL AND REGIONAL SUPPLY AND DEMAND DETERMINE THE OUTCOME IN TOTAL AND IN OUR OWN COUNTRIES. BUT MORE ABOUT THAT LATER. NOW, AS I BELIEVE THAT MANY OF YOU ARE NOT TOO FAMILIAR WITH INDONESIA, IT MAY BE USEFUL TO DEVOTE A FEW MINUTES TO SOME GENERAL INFORMATION ABOUT INDONESIA.

INDONESIA IS AN ARCHIPELAGO, ONE OF THE LARGEST IN THE WORLD, CONSISTING OF FIVE LARGE ISLANDS AND SOME 13,000 SMALLER ISLANDS. IT STRETCHES SOME 3,500 MILES BETWEEN THE ASIAN CONTINENT AND AUSTRALIA WITH AN AGGREGATE LAND AREA OF ABOUT

785,000 SQUARE MILES. IT HAS A POPULATION OF OVER 165 MILLION, THE FIFTH LARGEST IN THE WORLD, AND AN AVERAGE GNP OF $520 PER CAPITA IN 1985.

OIL OPERATIONS ARE NOT NEW IN INDONESIA. LAST YEAR INDONESIA CELEBRATED ITS OIL CENTENNIAL. THE FIRST COMMERCIAL DISCOVERY WAS MADE ON THE ISLAND OF SUMATRA IN 1885. BUT ACTUALLY, MODERN INDONESIAN OIL HISTORY STARTED ONLY ABOUT 20 YEARS AGO, SINCE WHAT WE CALL "THE NEW ORDER" CAME INTO POWER. PRODUCTION AT THAT TIME WAS 515 THOUSAND B/D COMPARED TO LAST MONTH'S CRUDE AND CONDENSATE PRODUCTION OF 1.45 MILLION B/D. PEAK PRODUCTION SO FAR WAS 1.71 MILLION B/D WHICH WAS ACHIEVED DURING 1977. PRODUCTION HAS INCREASED ALMOST THREEFOLD, AND KNOWN RECOVERABLE RESERVES TODAY ARE ALSO ABOUT THREE TIMES AS LARGE AS THEY WERE 20 YEARS AGO. FOR THE LAST FIVE YEARS, INDONESIA HAS BEEN EXPORTING AN AVERAGE OF ABOUT 925 THOUSAND B/D OF CRUDE AND CONDENSATE AND 135 THOUSAND B/D OF PRODUCTS.

DURING THE EARLY 70'S, HUGE GAS FIELDS WERE FOUND IN THE NORTHERN PART OF SUMATRA AND IN THE EASTERN PART OF KALIMANTAN, OR BETTER KNOWN AS BORNEO TO SOME OF YOU. SINCE 1973 INDONESIA HAS SUCCEEDED IN DEVELOPING NEW EXPORT MARKETS TO JAPAN FOR ITS GAS IN THE FORM OF LNG. ACTUAL LNG EXPORTS STARTED IN 1977. TODAY INDONESIA IS THE LARGEST EXPORTER OF LNG IN THE WORLD, HAVING

EXPORTED SOME 15 MILLION TONS LAST YEAR. EXPORTS TO SOUTH KOREA WILL HOPEFULLY START BEFORE THE END OF THIS YEAR.

INDONESIA HAS BEEN A MEMBER OF OPEC SINCE 1962. IN LINE WITH THE EFFORTS TO RESTORE CRUDE PRICES TO A REASONABLE LEVEL AND IN ACCORDANCE WITH THE OPEC CONFERENCE DECISION OF LAST MONTH, INDONESIA'S CRUDE PRODUCTION, STARTING THIS MONTH, WILL BE LIMITED TO AN AVERAGE OF 1.189 MILLION B/D. SO FAR PRICES HAVE REACTED FAVORABLY.

RESTORING OIL PRICES TO A REASONABLE LEVEL IS VERY IMPORTANT TO INDONESIA, AS OIL AND GAS REVENUES ARE STILL PLAYING AN IMPORTANT ROLE IN OUR INCOME. OUR LNG PRICES ARE ALSO DIRECTLY LINKED TO OIL PRICES. INCOME FROM OIL AND GAS IS THE BACKBONE OF OUR NATIONAL DEVELOPMENT PROGRAMS. FOR THE LAST TWELVE YEARS, OIL AND GAS REVENUES HAVE ALWAYS PROVIDED MORE THAN 50% OF THE DOMESTIC INCOME OF OUR STATE BUDGET.

IT IS MAYBE ALSO WORTHWHILE TO MENTION THAT, ALTHOUGH INDONESIA IS AN OIL EXPORTING COUNTRY, A POLICY OF DIVERSIFICATION AWAY FROM OIL, HAS BEEN VIGOROUSLY IMPLEMENTED. OIL'S SHARE IN THE DOMESTIC ENERGY MARKET HAS BEEN REDUCED TO SOME 68% LAST YEAR COMPARED TO OVER 90% SINCE THE START OF OUR FIRST FIVE YEAR PLAN. THE GROWTH IN DOMESTIC OIL CONSUMPTION, WHICH IN THE 70'S WAS AT AN ANNUAL AVERAGE OF 13%, OVER THE

LAST FIVE YEARS HAS SHOWN A NEGATIVE GROWTH OF ABOUT 0.1%. ASIDE FROM CONSERVATION, THIS SUCCESS HAS BEEN ACHIEVED THROUGH THE PRIORITY AND BETTER DOMESTIC UTILIZATION OF NON-EXPORTABLE ENERGY RESOURCES SUCH AS HYDRO-POWER AND GEOTHERMAL AND LESS EXPORTABLE COAL AND GAS.

THIS, IN A NUTSHELL, IS SOME GENERAL INFORMATION ON INDONESIA, WHICH I HOPE CAN GIVE YOU SOME FEEL FOR THE SITUATION AND PREVAILING CONDITIONS. I BELIEVE THAT THIS INTRODUCTION IS IMPORTANT TO BE ABLE TO EVALUATE THE POSSIBLE FUTURE DEVELOPMENTS IN THE INDONESIAN OIL SCENE, AND CONSEQUENTLY ITS EXPORTS. IT IS, IN SHORT, A DEVELOPING COUNTRY, TRYING TO IMPROVE LIVING CONDITIONS FOR ITS MORE THAN 165 MILLION PEOPLE. IT WELCOMES FOREIGN ASSISTANCE, INCLUDING FOREIGN INVESTMENTS IN OIL. THIS HAS BEEN THE CORNER-STONE OF OUR SUCCESSFUL OIL DEVELOPMENT EFFORT.

I HAVE BEEN ASKED BY THE ORGANIZERS TO TALK ABOUT THE SUBJECT OF OIL AND GAS DEVELOPMENT AND EXPORTS IN INDONESIA. IN ORDER TO BE ABLE TO PROPERLY ADDRESS THE SUBJECT I WOULD LIKE TO COMMENCE BY EXPLAINING SOME OF OUR FUNDAMENTALS CONCEPTS.

DEVELOPMENT OF OIL AND GAS, I BELIEVE, IS BASICALLY INFLUENCED BY THREE FACTORS WHICH ALSO IS TRUE FOR INDONESIA:

FIRST, AND FOREMOST, IS THE GEOLOGICAL CONDITION OF THE REGION, AND WHETHER IT IS OIL BEARING OR NOT. SECOND IS THE TERMS AND BUSINESS CONDITIONS UNDER WHICH OIL COMPANIES ARE INVITED TO WORK. AND LAST, BUT NOT LEAST, IS THE PRICE AT WHICH THE PRODUCT, IN OUR CASE OIL AND LNG, CAN BE SOLD.

FROM A GEOLOGICAL POINT OF VIEW, INDONESIA IS CONSIDERED A PROVEN OIL PROVINCE. THE INDONESIAN ARCHIPELAGO FORMS THE SOUTHEASTERN SALIENT OF THE GIANT EURASIAN CRUSTAL PLATE. IN THE CONTINENTAL SHELVES, NUMEROUS SEDIMENTARY BASINS DEVELOPED AND RECEIVED VAST AMOUNTS OF SEDIMENTS FROM THE ADJOINING CONTINENTS. THE SEDIMENTS WERE DEPOSITED ALMOST ENTIRELY IN A MARINE ENVIRONMENT, WHICH IS USUALLY FAVORABLE FOR HYDROCARBON GENERATION. THERE ARE ABOUT 60 TERTIARY SEDIMENTARY BASINS IDENTIFIED TODAY, LOCATED ONSHORE AS WELL AS OFF-SHORE, COVERING AN AREA OF ABOUT 1,000,000 SQUARE MILES.

EXCEPT FOR THREE STRETCHES OF OUR CONTINENTAL SHELF BOUNDARY, MOST OF IT HAS BEEN VERY WELL DELINIATED BY BILATERAL OR TRILATERAL AGREEMENTS WITH OUR NEIGHBORS. TWO EXCEPTIONS INVOLVE AREAS AND BOUNDARIES IN THE SOUTH CHINA SEA, WHICH IS BEING DISCUSSED FOR SETTLEMENT WITH VIETNAM, AND THE SO CALLED "TIMOR GAP", A SMALL PART OF OUR BOUNDARY YET TO BE SETTLED WITH AUSTRALIA IN AN AREA SOUTH OF THE ISLAND OF TIMOR. THE THIRD AREA LOCATED NORTH OF IRIAN JAYA, OR WEST NEW GUINEA AS IT MAY BE BETTER KNOWN TO YOU, IS STILL UNDEFINED.

OF THE 60 BASINS, ONLY 32 HAVE BEEN EXPLORED, AND TODAY 14 ARE PRODUCING. OF THE 14, ONLY ONE ON-SHORE BASIN IN CENTRAL SUMATRA HAS BEEN EXTENSIVELY DEVELOPED, CONTAINING TWO OF OUR BIGGEST FIELDS, NAMELY MINAS WITH 9 BILLION BARRELS OIP AND DURI WITH 7 BILLION BARRELS OIP. BUT THE SIZE OF THESE FIELDS ARE FOR INDONESIA, UNFORTUNATELY, THE EXCEPTION RATHER THAN THE RULE. TODAY 25% OF OUR PRODUCING FIELDS HAVE LESS THAN 10 MILLION BARRELS KNOWN RECOVERABLE RESERVES. MORE THAN 70% HAVE LESS THAN 100 MILLION BARRELS OF RECOVERABLE RESERVES. THIS SITUATION INDICATES THAT AT ANY GIVEN TIME, KNOWN RECOVERABLE RESERVES IN INDONESIA WILL BE RELATIVELY SMALL. BUT STUDIES MADE BY THE DEPARTMENT OF MINES AND ENERGY INDICATE SOME 50 BILLION BARRELS OF PRODUCEABLE OIL ARE STILL TO BE DISCOVERED.

LATELY THOUGH GIANT GAS FIELDS HAVE BEEN DISCOVERED INCLUDING ARUN (12 TCF) IN 1971, FOLLOWED BY BADAK (7 TCF) IN 1972. NATUNA, DISCOVERED IN 1981, HAS A HYDROCARBON RESERVE OF 45 TCF. AND THE PATTERN OF GAS DISCOVERIES IS STILL CONTINUING. A POTENTIAL OF 200 TCF IS STILL TO BE DISCOVERED AND PRODUCED.

A CLOSER LOOK INTO THE KNOWN BASINS WILL REVEAL THAT THE MAJORITY OF THE PRODUCING FIELDS ARE LOCATED IN THE SUNDA SHELF, IN THE WESTERN PART OF INDONESIA. THE MOST PLAUSIBLE REASON IS THAT THESE FIELDS ARE LOCATED CLOSER TO THE EXISTING

LOGISTICAL POINTS. AS A FORELAND BASIN, THEY ALSO HAVE PROVED TO BE PRODUCTIVE. HENCE THE OPERATING COMPANIES, RATHER THAN HUNT FOR RISKY VENTURES IN UNEXPLORED OR LESS EXPLORED BASINS, PREFER TO LOOK FOR FIELDS WHICH ARE LESS RISKY -- EVEN IF THEY ARE SMALL -- AND CLOSER TO EXISTING PRODUCING FACILITIES. WITHIN THE PRODUCING BASINS, NEW CONCEPTS APPLIED IN THE EXPLORATION PLAY, MAY ALSO PRODUCE SUCCESSFUL DISCOVERIES FOR A NEW CONTRACTOR IN PREVIOUSLY ABANDONED FIELDS. MOREOVER STRATIGRAPHIC PLAYS HAVE SO FAR PRACTICALLY NOT BEEN APPLIED. IN SEVERAL FIELDS, NUMEROUS CARBONATE PROSPECTS STILL EXIST AND ARE LIKELY TARGETS FOR MORE EXPLORATION DRILLING.

THE GREATER PART OF THE UNEXPLORED OR LESS EXPLORED BASINS, IS LOCATED IN THE REGIONS OF EAST INDONESIA, MOST OF IT IN DEEPER OFF-SHORE AREAS. THE EASTERN PART OF INDONESIA IS CONSIDERED RATHER REMOTE FROM A LOGISTICAL POINT OF VIEW, AND DEEPER WATERS INCREASE COSTS. UNFORTUNATELY, THIS AREA IS ALSO CONSIDERED MORE RISKY. THIS MAY BE BASED ON THE PERCEPTION THAT DEEP WATER BASINS HAVE LOWER POTENTIALS FOR HYDROCARBON ACCUMULATION. BUT A NUMBER OF DISCOVERIES HAVE BEEN MADE IN THIS PART OF THE COUNTRY, PROVING THAT THE EASTERN PART OF INDONESIA IS ALSO PRODUCTIVE. GRANTED, CONDITIONS MAY HAVE TO BE ADJUSTED TO MAKE THE PROSPECTS MORE ECONOMICALLY ATTRACTIVE, BUT THE POTENTIAL IS REAL.

ANOTHER POTENTIAL FOR ADDITIONAL RESERVES IS THROUGH ENHANCED OIL RECOVERY EFFORTS. THERE ARE CURRENTLY 235 FIELDS PRODUCING, OIL AS WELL AS GAS. MOST OF THEM ARE LOCATED ON-SHORE WITH ALMOST 6,000 PRODUCING WELLS. THE MAJORITY ARE STILL IN THE PRIMARY RECOVERY STAGE. ENHANCED OIL RECOVERY TECHNOLOGY HAS BEEN SUCCESSFULLY APPLIED IN SEVERAL FIELDS. A GOOD EXAMPLE IS THE GIANT MULTI-BILLION STEAM FLOOD PROJECT IN THE DURI FIELD IN CENTRAL SUMATRA. IT IS A WORLD CLASS VENTURE AND IF FULLY IMPLEMENTED, IT MAY WELL BECOME THE LARGEST STEAM FLOOD PROJECT IN THE WORLD. RECENT STUDIES SHOW THAT THIS AMBITIOUS PROJECT, WITH A PROJECT LIFE OF BETWEEN 40 - 60 YEARS, CAN RECOVER OVER 4 BILLION BARRELS ADDITIONAL CRUDE BY INCREASING THE RECOVERY FACTOR FROM 7% TO ABOUT 55%.

SO BASICALLY GEOLOGICAL AND RESERVOIR DATA INDICATE THAT INDONESIA POTENTIALLY WILL STILL QUALIFY AS AN OIL PRODUCER AND EXPORTER WELL INTO THE NEXT CENTURY. THE QUESTION CONTINUES TO BE, HOW TO ACHIEVE THAT GOAL? WE HAVE CHOOSEN THE PATH OF COOPERATION WITH FOREIGN CAPITAL. OUR OIL AND GAS LAW NO. 44/PRP OF 1960 SET THE STAGE OF COOPERATION WITH FOREIGN OIL COMPANIES, WHICH WAS AGAIN RE-EMPHASIZED IN THE LAW NO. 8 OF 1971, ESTABLISHING THE STATE OIL COMPANY PERTAMINA. THE CREATION OF A STATE OIL COMPANY CAN BE VIEWED AS A "COMPROMISE" BETWEEN THE TWO SCHOOLS OF THOUGHT: DO IT YOURSELF WITH YOUR OWN CAPITAL AND GET THE WHOLE REVENUE OR USE SOMEONE ELSE'S

CAPITAL AND SHARE THE RESULTS. ON THE ONE HAND LETTING MOST OF THE FOREIGN CAPITAL EXPLORE AND EXPLOIT THE NATION'S VAST RICHES, WHILE ON THE OTHER HAND MAINTAINING THE NATION'S ABILITY TO HANDLE OIL OPERATIONS BY HAVING A PARTIAL, ALTHOUGH VERY SMALL, PLOW-BACK OF THE NATION'S OIL INCOME INTO OIL OPERATIONS. PERTAMINA'S SHARE IN OIL PRODUCTION IS ONLY ABOUT 5%. BUT IT IS A FULLY INTEGRATED OIL COMPANY, IT OWNS AND OPERATES ALL DOMESTIC REFINERIES AND LNG PLANTS, AND ALL DISTRIBUTION AND SHIPPING OPERATIONS TO SUPPLY ALL OF THE DOMESTIC FUEL REQUIREMENTS. BY CONDUCTING ITS OWN INTEGRATED PETROLEUM OPERATIONS PERTAMINA IS BETTER ABLE TO SUPERVISE THE FOREIGN CONTRACTORS' OIL OPERATIONS IN A BUSINESS WAY, THAT IS, BY TALKING IN THE SAME LANGUAGE.

COOPERATION BETWEEN PERTAMINA AND THE FOREIGN OIL COMPANIES, HAS INDEED BEEN VERY INSTRUMENTAL IN SUCCESSFULLY FINDING AND DEVELOPING OIL AND GAS IN THE LAST TWO DECADES. THE COOPERATION IS BEING ACHIEVED VIA A PRODUCTION SHARING CONTRACT. A CONTRACTOR IS REQUIRED TO FINANCE ALL EXPLORATION, DEVELOPMENT AND PRODUCTION RELATING TO OIL AND GAS RESOURCES WITHIN A SPECIFIC AREA. THE TERMS OF THE INITIAL CONTRACTS CALLED FOR A 65:35 SPLIT IN THE SHARE OF OIL IN FAVOR OF THE GOVERNMENT. THE CONTRACTOR WAS ALLOWED UP TO 40% OF ANNUAL CRUDE PRODUCTION FOR COST RECOVERY BEFORE THE SPLIT. PRIMARILY BECAUSE OF THE SHARP INCREASES IN CRUDE OIL PRICES IN THE MID 70'S, THE GOVERNMENT, LIKE ALL OTHER GOVERNMENTS

IN THE WESTERN WORLD, ENTERED INTO NEGOTIATIONS WITH THE CONTRACTORS TO MODIFY THE THEN EXISTING AGREEMENTS. THE NEW TERMS, AGREED UPON IN 1978, BASICALLY CALLS FOR AN 85:15 SPLIT OF THE SHARED OIL, WHILE COST RECOVERY IS BASED ON ACCEPTED ACCOUNTING PRINCIPLES.

THE PRODUCTION SHARING CONTRACT IN ITS ORIGINAL FORM AND THE MODIFICATIONS THEREOF, JUDGING FROM THE RESULTS OF INDONESIA'S OIL OPERATIONS, SEEMS TO HAVE GIVEN THE NECESSARY INCENTIVE TO DO THE JOB. BUT TO ASSURE FUTURE DEVELOPMENT, WE MUST ALWAYS BE WILLING TO REVIEW OUR TERMS AND CONDITIONS TO DETERMINE IF WE ARE PROVIDING THE OIL COMPANIES WITH THE NECESSARY INCENTIVES. IF WE ARE TO REMAIN AN OIL PRODUCER AND EXPORTER WELL INTO THE NEXT CENTURY, WE CANNOT ALLOW OURSELVES THE LUXURY OF IGNORING COMPETITIVE CONDITIONS ELSEWHERE.

IT IS OF COURSE IMPOSSIBLE TO STATE HERE AND NOW WHAT WOULD BE REQUIRED, IF ANYTHING AT ALL, TO STRUCTURE INDONESIAN PRODUCTION SHARING CONTRACTS IN LINE WITH FUTURE NEEDS. TECHNICALLY AND FINANCIALLY, NEWER FINDS WILL BE MORE DIFFICULT AND CONSEQUENTLY COSTLIER -- DIFFICULT BECAUSE OF REMOTENESS OR DEEPER OFF-SHORE AREAS. THE TREND TOWARDS A LARGER SHARE OF OFF-SHORE PRODUCTION IN INDONESIA, IS DEFINITELY THE CASE. BUT AS OIL REVENUES ARE AN IMPORTANT PART OF OUR DEVELOPMENT EFFORTS, WHETHER WE LIKE IT OR NOT, WE HAVE TO BE RESPONSIVE TO WHATEVER IS REASONABLY REQUIRED.

ASIDE FROM FINANCIAL CONDITIONS, POLITICAL CONDITIONS ALSO PLAY AN IMPORTANT ROLE. WE HAD OUR SHARE OF POLITICAL INSTABILITY, WHERE EVERYTHING, INCLUDING ECONOMIC STABILITY, WAS SACRIFICED FOR POLITICAL GOALS. SINCE THE NEW ORDER GOVERNMENT WAS ESTABLISHED IN 1966, HOWEVER, DEVELOPMENT EFFORTS ARE THE PRIMARY MOTIVATION FOR ALMOST ALL OF OUR ACTIONS. THE POLITICAL STABILITY TODAY ATTRIBUTES TO OUR SUCCESS IN OIL DEVELOPMENT. I BELIEVE THAT THOSE OF YOU HERE TODAY, WHO HAVE OIL ACTIVITIES IN INDONESIA, CAN BEAR WITNESS TO THAT STATEMENT.

IN THIS CONTEXT, I WOULD LIKE TO DRAW YOUR ATTENTION TO A CONDITION WHICH IS SPECIFIC TO AN OIL PRODUCER LIKE INDONESIA. BECAUSE OF THE RELATIVELY SMALL SIZE OF THE RESERVES SCATTERED THROUGHOUT INDONESIA, ALMOST NO ONE ACTUALLY HAS RESERVES AVAILABLE WITH LONG LIVES. SO CONTINUOUS EXPLORATION PROGRAMS ARE A PRECONDITION FOR OUR FUTURE. BY THE SAME TOKEN, CONTINUING EXPLORATION REQUIRES A CONTINUOUS PRESENCE OF FOREIGN OIL COMPANIES, AS WE ARE NOT IN A POSITION TO FINANCE ALL OF THE ACTIVITY OURSELF. SO, FOR ALL PRACTICAL PURPOSES, WE ARE BOUND TO WORK IN PARTNERSHIP WITH THE FOREIGN OIL COMPANIES IF WE WANT TO CONTINUE TO BE AN OIL PRODUCER. THIS ACTUALLY IS THE BEST GUARANTEE ANY FOREIGN OIL COMPANY WORKING IN INDONESIA CAN HAVE. AND THIS IS ACTUALLY THE GREATEST DIFFERENCE BETWEEN INDONESIA AND SAY A PRODUCING COUNTRY IN THE

MIDDLE EAST. WE CONSIDER FOREIGN OIL CONTRACTORS AS OUR PARTNERS, WITH A MUTUAL RESPECT FOR EACH OTHER, AND AN UNDERSTANDING FOR EACH SIDE'S PROBLEMS.

THE THIRD VERY IMPORTANT FACTOR IS OF COURSE THE PRICE OF OIL, THE COMMODITY WE PRODUCE AND SELL. THE PRICE INCREASES OF THE 70'S, WHILE BENEFITTING OIL PRODUCERS, AT THE SAME TIME CAUSED FORCES TO REDUCE OIL DEMAND. CONSERVATION AND DIVERSIFICATION ARE THE BEST EXAMPLES OF THE FACTORS WHICH HAVE REDUCED OIL DEMAND. BUT MORE IMPORTANT HAS BEEN THE FACT THAT HIGHER OIL PRICES ENABLED EXPLORATION AND DEVELOPMENT OF HIGH COST OIL RESERVES WHICH OTHERWISE WOULD NOT HAVE BEEN FEASIBLE. THE AFTERMATH OF HIGH OIL PRICES HAS BEEN THAT A VAST AMOUNT OF OIL BECAME AVAILABLE IN A FAST SHRINKING WORLD OIL DEMAND SITUATION. WITHOUT LOOKING FOR SCAPEGOATS, THE EFFECT HAS BEEN A STRONG PRESSURE ON OIL PRICES. WE ALL HAVE FELT THE RESULT OF IT SINCE THE BEGINNING OF THE 80'S, BUT ESPECIALLY IN THE LAST 9 MONTHS.

BUT BE THAT IT AS IT MAY, WHAT EFFECT DO THESE DECLINING PRICES HAVE ON OIL DEVELOPMENT IN INDONESIA? PRIVATE OIL COMPANIES BASICALLY ARE NOT LOOKING FOR OIL PER SE. THEY ARE CONCERNED WITH MAKING A SATISFACTORY RETURN ON THEIR INVESTMENT. WHAT CAN BE OBSERVED SO FAR IN INDONESIA IS THAT THE NEGATIVE EFFECTS ARE SURPRISINGLY SMALL. WE DID HAVE TO WAIVE TEMPORARILY THE SO-CALLED GOVERNMENT SELLING PRICE OR

G.S.P. IN FAVOR OF A MARKET RELATED MONTH-BY-MONTH PRICE WHICH IS DETERMINED BY MUTUALLY AGREED UPON COMPANY-BY-COMPANY SPECIFIC FORMULAS. THEY ARE NOT NET-BACK CALCULATIONS, BUT PRICES PREDETERMINED BEFORE THE LIFTINGS START AT THE BEGINNING OF EACH MONTH. THIS PRICE SETTING MODIFICATION SEEMS TO BE FULFILLING THE COMPANIES REQUIREMENTS. BASED ON THE GOVERNMENT'S REQUEST, MOST OF THE COMPANIES HAVE NOT REDUCED THEIR EXPLORATION ACTIVITIES, BUT ARE PREPARING FOR BETTER TIMES AHEAD WHEN DEMAND WILL INCREASE. AS I HAVE EXPLAINED EARLIER, THE SMALL SIZE FIELDS IN INDONESIA REQUIRE THAT EXPLORATION BE CONTINUED YEAR AFTER YEAR SO AS NOT TO REDUCE OUR ABILITY NOT ONLY TO INCREASE PRODUCTION BUT ALSO TO MAINTAIN OUR PRODUCTION CAPACITY. WE HAVE LEARNED OUR LESSON: DURING 1976 - 1977, WHEN THE GOVERNMENT NEGOTIATED THE MODIFICATION OF THE PRODUCTION SHARING CONTRACTS WHICH LEAD TO AN AGREEMENT IN 1978, THE CLIMATE OF UNCERTAINTY CAUSED THE COMPANIES TO DISCONTINUE EXPLORATION EFFORTS. THE RESULT WAS AN IMMEDIATE FALL IN PRODUCTION IN 1978 AND, OF GREAT SIGNIFICANCE, THE DECLINE COULD NOT BE ARRESTED UNTIL FOUR YEARS LATER, WHILE DURING THAT TIME PERIOD OIL PRICES WERE AT THEIR BEST. IT WAS A VERY EXPENSIVE LESSON.

BUT MARKET RELATED PRICES MAY NOT BE ENOUGH SHOULD OIL PRICES FALL FOR INSTANCE TO A $5/BBL LEVEL OR THERE ABOUT FOR A RELATIVELY LONG PERIOD OF TIME. IT CAN BE A LONG TERM DISASTER.

ALTHOUGH IT WILL NOT IMMEDIATELY STOP OIL PRODUCTION AND EXPORTS FROM INDONESIA. ALTHOUGH THE AVERAGE COST OF PRODUCTION IS BELOW $5/BBL, THE PICTURE IS SOMEWHAT DISTORTED AS ABOUT 40% IS WELL BELOW $2/BBL. HOWEVER, SEEKING FUTURE POSSIBILITIES MAY BE VERY MUCH AFFECTED. ALMOST EVERY OIL COMPANY BELIEVES THAT A VERY LOW PRICE LIKE $5/BBL CANNOT REMAIN FOR A VERY LONG TIME. CASH-FLOW PROBLEMS MAY RESTRAIN EXPLORATION ACTIVITIES. STEAM FLOODING FOR ENHANCED OIL RECOVERY FOR INSTANCE MAY ALSO NOT BE IN THE BALL GAME. AND INDONESIA, I BELIEVE, IS NOT THE EXCEPTION.

BUT WHATEVER HAPPENS TO OIL PRICES, IT WILL NOT INFLUENCE OUR ABILITY TO PRODUCE AND EXPORT GAS IN THE FORM OF LNG AND LPG. THE AVAILABLE PROVEN RECOVERABLE NON-ASSOCIATED GAS RESERVES PUTS US IN THE SAME POSITION IN GAS AS THE MIDDLE EAST PRODUCERS ARE IN OIL. I WOULD EVEN SAY MUCH BETTER THAN THE PRESENT LNG EXPORT FROM THE MIDDLE EAST. DECLINING OIL PRICES WILL DEFINITELY INFLUENCE OUR REVENUES FROM GAS, BUT NOT THE DEPENDENCY FOR OUR GAS EXPORTS.

HAVING SAID ALL THIS, HOW WILL INDONESIA'S FUTURE OIL DEVELOPMENT AND EXPORTS LOOK ? GEOLOGICALLY, THE PHYSICAL POSSIBILITY FOR STILL BEING AN OIL PRODUCER AND EXPORTER WELL INTO THE NEXT CENTURY IS THERE. IF SO REQUIRED, I BELIEVE PAST EXPERIENCES HAVE SHOWN THE PRAGMATIC APPROACH INDONESIA CAN

TAKE IN TERMS OF MAINTAINING ITS COMPETITIVE ADVANTAGE IN OIL DEVELOPMENT CONDITIONS. OF COURSE, CHANGES LIKE THIS CANNOT BE EXPECTED TO HAPPEN OVERNIGHT OR TO CHANGE DAY BY DAY. THE KEY MAY BE THE LEVEL OF OIL PRICES IN THE FORESEEABLE FUTURE. IN MY OWN JUDGEMENT IF PRICES STABILIZE AT LEAST TO ABOUT $13 TO $15 PER BARREL, THE EFFECT WOULD BE MINIMAL ON THE CONTINUATION OF INDONESIAN OIL OPERATIONS.

WHAT FUTURE LEVEL OF CRUDE PRODUCTION AND EXPORTS CAN BE EXPECTED? TO ANSWER THIS QUESTION IS OF COURSE TAKING A VERY LONG SHOT IN THE DARK. THE SAME QUESTION WAS ALSO POSED SOME TEN YEARS AGO. UNDER THE THEN EXISTING CONDITIONS MY ANSWER AT THAT TIME WAS "I SEE NO REASON WHY IT CANNOT REACH 2 MILLION B/D". UNDER PRESENT DAY CONDITIONS, HOWEVER, I HAVE TO MODIFY MY OPINION. I BELIEVE, IF THERE WERE NO OPEC PRODUCTION LIMIT, INDONESIA COULD WELL SUSTAIN, FOR A LONG TIME, A LEVEL OF OVER 1.6 MILLION B/D OF CRUDE AND CONDENSATE PRODUCTION, WHICH LEVEL COULD BE REACHED WITHIN A SHORT TIME.

HOW ABOUT THE EXPORT POSSIBILITIES? LET US LOOK AT THE PERFORMANCE IN THE PAST TEN YEARS. THE TABLE SHOWS THAT TOTAL EXPORTS OF CRUDE AND PRODUCTS HAVE BEEN IN THE RANGE OF 1.0 TO 1.1 MILLION B/D WITH AN AVERAGE OF 51% GOING TO JAPAN AND 30% GOING TO THE USA AS THE MAIN DESTINATION. THE AREA TO THE NORTH AND EAST, AWAY FROM THE MIDDLE-EAST, IS CONSIDERED OUR "NATURAL MARKET". WITH THE OPEC PRODUCTION RESTRICTION IN

FORCE. INDONESIA'S EXPORT OF CRUDE, INCLUDING CONDENSATE AND PRODUCT, IS LIKELY TO REMAIN AT THE 1 MILLION B/D RANGE. WITH AN INCREASE OF PRODUCTION IN THE FUTURE TO SAY ABOUT 1.6 MILLION B/D, WE MAY AGAIN RESTORE OUR EXPORT POTENTIAL TO ABOUT 1.3 MILLION B/D. I DO NOT FORESEE MARKETING DIFFICULTIES.

	CRUDE & PRODUCT EXPORTS (MBPCD)				LNG EXPORTS (MILLION TONS)
YEAR	JAPAN	U.S.A.	OTHERS	TOTAL	JAPAN
1976	618	501	208	1,327	
1977	734	509	227	1,470	0.5
1978	651	471	282	1,404	3.7
1979	741	363	157	1,261	6.3
1980	676	329	176	1,181	8.5
1981	620	278	289	1,187	8.6
1982	558	201	227	986	9.0
1983	510	309	221	1,040	9.6
1984	557	312	280	1,149	14.2
1985	468	283	187	938	15.0

EXPORTS OF LNG HAVE BEEN RISING STEADILY, AND NEXT YEAR WILL BE OVER 17 MILLION TONS. PRODUCTION CAN EASILY BE DOUBLED OR TRIPLED, BUT MARKETING POSSIBILITIES WILL BE THE BIGGEST CONSTRAINT. LNG IS BASICALLY A REGIONALLY TRADED PRODUCT. IN THE WESTERN PACIFIC, ASIDE FROM RELATIVELY MODEST-SIZED MARKETS IN KOREA AND TAIWAN, JAPAN IS THE MAIN CONSUMER. ALTHOUGH JAPAN HAS PUT A CERTAIN CAP ON THAT POTENTIAL WE BELIEVE THAT OUR PRESENT PRODUCTION OF 15 MILLION TONS OF LNG, CAN BE INCREASED BY ANOTHER THIRD OVER THE NEXT TEN YEARS.

I HOPE THAT THE VIEWS I SHARE WITH YOU TODAY MAY BE HELPFUL TO YOUR UNDERSTANDING AND TO THESE DELIBERATIONS. I REGRET THAT I AM NOT ABLE TO PRESENT MORE SPECIFIC FIGURES. ALTHOUGH I WOULD LIKE TO APPROACH THIS SUBJECT WITH CONSIDERABLE OPTIMISM THERE ARE SO MANY UNCONTROLLABLE FACTORS WHICH MAKE REALISTIC PRODUCTION FORECASTS EXTREMELY DIFFICULT. HAVING SAID THIS, I STILL CANNOT RESIST FROM BEING A SALESMAN --- I HOPE THAT MY TALK WILL INDUCE SOME OF THE OIL COMPANIES PRESENT HERE TODAY, WHO ARE NOT YET WORKING IN INDONESIA, TO TRY THEIR LUCK IN INDONESIA. HOPEFULLY THEY WILL BE SUCCESSFUL. I CAN ASSURE YOU THAT YOU WILL FIND IT A GOOD PLACE TO DO BUSINESS.

THANK YOU VERY MUCH FOR YOUR ATTENTION.

CALGARY, 15 SEPTEMBER 1986

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EXPLORATION AND DEVELOPMENT PROSPECTS
IN THE PACIFIC RIM

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PAPER PRESENTED TO INTERNATIONAL OIL & GAS MARKETS CONFERENCE,
CALGARY, ALBERTA, SEPTEMBER 14-16, 1986

EXPLORATION AND DEVELOPMENT PROSPECTS IN THE PACIFIC RIM

MALCULM W. BOYCE
CHEVRON OVERSEAS PETROLEUM INC.

(SLIDE 1)

I APPRECIATE THE OPPORTUNITY TO ATTEND THIS CONFERENCE, AND TO ADDRESS OIL AND GAS PROSPECTS IN THE PACIFIC RIM.

TODAY WE'VE BEEN HEARING, AND DISCUSSING, PRINCIPALLY THE MARKET SIDE OF PETROLEUM THROUGHOUT THE WESTERN PACIFIC REGION. I'LL NOW ASK YOU TO TURN YOUR ATTENTION TO THE SOURCE OF OIL AND GAS SUPPLIES, BOTH THOSE DISCOVERED TO DATE, AND THOSE THAT THE PETROLEUM INDUSTRY HOPES TO FIND IN THE FUTURE.

(SLIDE 2)

THIS WORLD MAP SHOWS THE MOST SIGNIFICANT PETROLEUM BASINS IN THE PACIFIC RIM. THE WESTERN PACIFIC HAS BEEN DIVIDED, FOR PURPOSES OF DISCUSSION, INTO THREE REGIONS - NORTH, CENTRAL, AND SOUTH - AND I'LL DISCUSS EACH REGION WITH DETAILED MAPS. SPECIFICALLY, I WILL ATTEMPT TO PINPOINT THOSE BASINS THAT ARE CURRENTLY PRODUCING, OR ARE PREDICTED TO PRODUCE, SUBSTANTIAL QUANTITIES OF PETROLEUM THAT WILL SIGNIFICANTLY IMPACT PACIFIC RIM MARKETS. I WILL ALSO SHOW INDIVIDUAL COUNTRY STATISTICS OF DISCOVERED OIL AND GAS RESERVES AND FUTURE POTENTIAL.

BEFORE TURNING TO THE DETAILED MAPS, HOWEVER, I WOULD LIKE TO ADDRESS TWO POSSIBLE NORTH AMERICAN SOURCES OF PETROLEUM THAT COULD AFFECT WESTERN PACIFIC MARKETS:

THE FIRST IS NORTH SLOPE ALASKAN OIL, SHIPPED THROUGH THE TRANS-ALASKA PIPELINE TO TERMINAL FACILITIES AT VALDEZ. AS I'M SURE ALL OF YOU ARE AWARE, CURRENT U.S. LAW PROHIBITS EXPORTS OF THIS CRUDE, A POLICY DESIGNED TO REDUCE U.S. DEPENDENCE ON IMPORTED OIL. THE PETROLEUM INDUSTRY, HOWEVER, HAS CONTINUED TO SEEK CONGRESSIONAL APPROVAL TO EXPORT ALASKAN CRUDE TO PACIFIC MARKETS BECAUSE OF THE OBVIOUS ECONOMIC EFFICIENCY. THERE IS OPTIMISM THAT CONGRESS WILL SOON PASS LEGISLATION TO PERMIT EXPORT OF COOK INLET OFFSHORE OIL; HOWEVER, AUTHORIZATION TO EXPORT NORTH SLOPE CRUDE STILL APPEARS TO BE ONLY A DISTANT HOPE.

A SECOND NORTH AMERICAN AREA WORTH MENTIONING IS THE QUEEN CHARLOTTE BASIN ON CANADA'S WEST COAST. THIS AREA HAS BEEN IN MORATORIUM SINCE 1971 - FOR ENVIRONMENTAL REASONS - BUT THERE IS RENEWED OPTIMISM IN CANADA THAT THE AREA WILL SOON BE RE-OPENED FOR EXPLORATION DRILLING. INDUSTRY'S BEST GUESS IS THAT THE BASIN WILL YIELD PRIMARILY GAS. POSSIBLE FUTURE RESERVES FOR QUEEN CHARLOTTE AND SURROUNDING WEST COAST BASINS ARE IN THE 10 TCF RANGE.

(SLIDE 3)

THIS SLIDE DETAILS PETROLEUM BASINS OF PARTICULAR INTEREST IN THE NORTHWEST PACIFIC REGION. HIGHLIGHTED ARE THOSE BASINS WITH SIGNIFICANT QUANTITIES OF OIL RESERVES DISCOVERED TO DATE.

SONGLIAO AND THE NORTH CHINA BASIN EACH HOLD ENORMOUS QUANTITIES OF OIL -- REPORTEDLY OVER 6 BILLION BARRELS OF REMAINING RESERVES IN SONGLIAO, AND 8 BILLION BARRELS IN NORTH CHINA.

SONGLIAO CONTAINS CHINA'S LARGEST FIELD, DAQING, WITH REMAINING RESERVES OF ABOUT 6 BILLION BARRELS AND AVERAGE PRODUCTION OF OVER A MILLION BARRELS A DAY, ACCOUNTING FOR HALF OF CHINA'S NATIONAL OUTPUT. THE NORTH CHINA BASIN INCLUDES THE GIANT SHENGLI FIELD, WITH REMAINING RESERVES IN THE 3 BILLION BARREL RANGE, AND AVERAGE PRODUCTION OF OVER A HALF MILLION BARRELS A DAY.

CHINA'S CURRENT PRODUCTION IS OVER 2 MILLION BARRELS PER DAY, WITH ONE-QUARTER OF THIS PRODUCTION NOW EXPORTED, PRINCIPALLY TO JAPAN. CHINA IS ATTEMPTING TO DOUBLE ITS PRODUCTION BY THE YEAR 2000, BY ADDING NEW RESERVES IN THE BASINS IDENTIFIED ON THE NEXT SLIDE.

(SLIDE 4)

THROUGHOUT TODAY'S TALK I'LL BE DISCUSSING BOTH OIL RESERVES AND OIL POTENTIAL. OIL RESERVES ARE THOSE ACCUMULATIONS THAT HAVE ALREADY BEEN DISCOVERED, BUT NOT YET PRODUCED. OIL POTENTIAL REFERS TO A PREDICTION OF FUTURE RESERVES, BASED ON GEOLOGIC

ASSESSMENT OF THE AREAS IN QUESTION. OF COURSE, THE POTENTIAL FIGURES ARE MUCH THE SOFTER OF THE TWO NUMBERS. I MIGHT ADD THAT MOST OF THE FIGURES PRESENTED HERE ARE DERIVED FROM PUBLISHED SOURCES, ALTHOUGH SOME OF THE POTENTIAL PREDICTIONS ARE BASED ON OUR OWN BASIN STUDIES AT CHEVRON OVERSEAS. ALSO, PLEASE NOTE THAT ALL ESTIMATES FOR OIL INCLUDE GAS CONDENSATE.

CHINA HAS SOME HOPE OF ADDING SIGNIFICANT NEW RESERVES IN THE PROLIFIC SONGLIAO AND NORTH CHINA BASINS. HOWEVER, BOTH BASINS ARE REACHING A MATURE STAGE OF EXPLORATION, AND FUTURE RESERVES WILL BECOME INCREASINGLY DIFFICULT TO FIND AND UNLIKELY TO BE LARGE.

CHINA'S GREATEST HOPES FOR ADDING NEW RESERVES, AND REPLACING NEAR-TERM PRODUCTION DECLINES, APPEAR TO LIE IN THE WESTERN BASINS -- TARIM, JUNGGAR, AND QAIDAM. CHINESE EXPLORATION TO DATE HAS FOCUSED ON THE BASIN MARGINS, AND HAS DEMONSTRATED THAT THE AREAS ARE OIL-PRONE. THE JUNGGAR BASIN EVEN HAS LIMITED PRODUCTION -ABOUT 100,000 BARRELS OF OIL PER DAY -- TRANSPORTED BY RAIL TO CENTRAL CHINA MARKETS. HOWEVER, THE VAST UNEXPLORED INTERIOR PORTIONS OF THE WESTERN BASINS COULD CONTAIN RESERVES IN THE 4 TO 15 BILLION BARREL RANGE.

A SIGNIFICANT LIMITING FACTOR OF NOTE IS THE INACCESSIBILITY OF THE BASINS, SPECIFICALLY THEIR DISTANCE FROM AN EXPORT MARKET. THE SLIDE SHOWS SCHEMATICALLY A 3000 MILE PIPELINE THAT WOULD BE REQUIRED TO TRANSPORT WESTERN BASIN CRUDE TO EAST COAST MARKETS

AND EXPORT FACILITIES.

THE NEXT SLIDE IS A VIEW OF THE FARWESTERN TARIM BASIN (SLIDE 5) A HIGH DESERT AREA OF SAND DUNES AND EXTREME CLIMATIC CHANGES -- THAT MAY GIVE YOU SOME FEEL FOR THE REMOTENESS OF THE REGION AND THE SEVERITY OF WORKING CONDITIONS. THE PAVED ROAD AND TELEPHONE LINES ARE GENERALLY EXTREMELY RARE IN THIS AREA.

(SLIDE 6)

RETURNING TO THE NORTHERN MAP, NOTE THAT TWO OFFSHORE AREAS ARE HIGHLIGHTED FOR POSSIBLE FUTURE OIL DISCOVERY. THE PEARL RIVER MOUTH BASIN HAS RECENTLY BEEN ACTIVELY EXPLORED BY INTERNATIONAL OIL COMPANIES WITH MODEST RESULTS. IT NOW APPEARS THAT ONLY SMALL TO MEDIUM SIZED OIL ACCUMULATIONS ARE PRESENT, AND IT IS UNLIKELY THAT THIS BASIN WILL CONTRIBUTE SIGNIFICANTLY TO CHINA'S OIL SUPPLIES. THIS HAS BEEN A MAJOR DISAPPOINTMENT TO THE INDUSTRY AND THE CHINESE.

THE EAST CHINA SEA AREA HAS BEEN LIGHTLY EXPLORED BY THE CHINESE, BUT HOLDS POTENTIAL FOR SIGNIFICANT NEW RESERVES IN SHALLOW WATER. INTERNATIONAL BOUNDARIES HERE ARE STILL UNRESOLVED.

IN SUMMARY, CHINA HAS VERY LARGE OIL RESERVES, BUT MOST OIL PROVEN TO DATE IS IN A MATURE STAGE OF DEVELOPMENT -- AT OR NEAR PEAK PRODUCTION -- WITH PRODUCTION DECLINES LIKELY IN THE EARLY 1990'S. TO MAINTAIN CURRENT PRODUCING LEVELS, AND, IN

PARTICULAR, TO MEET THEIR STATED GOAL OF DOUBLING PRODUCTION BY THE YEAR 2000, CHINA MUST COUNT ON DEVELOPMENT OF ITS WESTERN BASINS. THIS, IN TURN, POSES ENORMOUS TECHNICAL AND -- MORE IMPORTANTLY -- ECONOMIC PROBLEMS OF LONG PIPELINE TRANSPORTATION.

(SLIDE 7)

WE'LL NOW SHIFT OUR FOCUS TO GAS PROSPECTS IN THE NORTHERN REGION.

HIGHLIGHTED HERE ARE BASINS WHERE SIGNIFICANT QUANTITIES OF GAS HAVE BEEN DISCOVERED, AND DEVELOPMENT IS ALREADY IN PLACE OR FIRMLY PLANNED. THESE INCLUDE THE SICHUAN BASIN, WITH AN ESTIMATED 10 TCF OF DEVELOPED GAS RESERVES IN A LARGE NUMBER OF MODERATE-SIZED FIELDS; AND THE SONGLIAO AND NORTH CHINA BASINS, WITH SIGNIFICANT GAS ASSOCIATED WITH THEIR MAJOR OIL PRODUCTION. ALSO NOTE THE AKITA AND NIIGATA BASINS ON THE WEST COAST OF JAPAN, CONTAINING A LITTLE OVER ONE TCF OF GAS RESERVES.

(SLIDE 8)

THIS NEXT SLIDE INCLUDES DISCOVERED GAS RESERVES THAT HAVE NOT YET BEEN DEVELOPED.

THE PACIFIC RIM CONTAINS VAST QUANTITIES OF UNDEVELOPED GAS, MUCH OF WHICH WILL BE UNECONOMIC TO DEVELOP IN THE NEAR TERM. TO EMPHASIZE THIS FACT, THROUGHOUT THE TALK I WILL DISTINGUISH BETWEEN DEVELOPED AND UNDEVELOPED GAS RESERVES.

THE LARGEST UNDEVELOPED RESERVES FALL WITHIN THE SICHUAN BASIN -- PERHAPS HALF OF THE BASIN'S TOTAL GAS RESERVES, OR ABOUT 10 TCF, ARE IN THIS CATEGORY. ALSO, THE NORTH CHINA BASIN HAS LARGE REPORTED GAS RESERVES -- IN THE 8 TCF RANGE -- PRESUMABLY ASSOCIATED WITH OIL PRODUCTION. NO DEVELOPMENT PLANS HAVE BEEN REPORTED.

IN THE SOUTH CHINA SEA, RECENT EXPLORATION IN THE YING-GE-HAI BASIN HAS DISCOVERED OVER 3 TCF OF GAS RESERVES, AND DEVELOPMENT PLANS ARE UNDERWAY TO TIE THIS ONSHORE TO A PROPOSED GAS GRID.

OUTSIDE OF CHINA, THE MOST SIGNIFICANT RESOURCE IS ON SAKHALIN ISLAND, WHERE JOINT RUSSIAN-JAPANESE INTERESTS HAVE DISCOVERED CLOSE TO 12 TCF OF GAS, WITH SOME ASSOCIATED OIL AND CONDENSATE. DEVELOPMENT PLANS FOR AN LNG PROJECT AT THE CHAIVO FIELD -THE FIRST FIELD PLANNED FOR DEVELOPMENT -- ARE ON HOLD BECAUSE OF CURRENT MARKET PRICES. PLEASE NOTE THAT ALL RESERVE FIGURES SHOWN HERE FOR THE U.S.S.R. PERTAIN ONLY TO SAKHALIN ISLAND.

(SLIDE 9)

IN TERMS OF GAS POTENTIAL WITHIN THIS AREA, ESTIMATES OF FUTURE RESERVES IN CHINA VARY FROM 10 TO 200 TCF. THE BULK OF THIS GAS IS EXPECTED WITHIN THE ONSHORE BASINS, INCLUDING VERY SIGNIFICANT EXPECTATIONS FOR THE WESTERN BASINS. HOWEVER, BECAUSE

OF LIMITED DOMESTIC MARKETS, AND THE ECONOMICS OF LIQUEFACTION, MUCH OF THIS RESOURCE BASE WILL REMAIN UNDEVELOPED FOR THE FORSEEABLE FUTURE.

(SLIDE 10)

I WOULD NOW LIKE TO MOVE TO THE CENTRAL REGION OF THE WESTERN PACIFIC, AN AREA INCLUDING BRUNEI, INDONESIA, MALAYSIA, THAILAND, AND VIETNAM.

THIS AREA IS DOMINATED BY THE VAST RESOURCES OF INDONESIA. HOWEVER, MR. WIJARSO, IN THE PRECEDING PRESENTATION, HAS ADDRESSED THIS AREA VERY THOROUGHLY, SO I WOULD LIKE TO CONCENTRATE INSTEAD ON PETROLEUM BASINS IN THE SURROUNDING COUNTRIES.

FIRST, MALAYSIA. AS INDICATED ON THE MAP, MALAYSIA HAS TWO AREAS OF VERY SIGNIFICANT OIL RESERVES. FIRST IS THE OFFSHORE EAST COAST OF PENINSULAR MALAYSIA, WHICH WILL BE REFERRED TO IN THIS TALK AS THE PENYU BASIN AREA. SECOND IS THE SARAWAK BASIN IN EASTERN MALAYSIA.

THE PENYU BASIN CONTAINS OIL RESERVES IN THE 2 BILLION BARREL RANGE. THE FIRST FIELD WAS DISCOVERED IN 1971, AND THERE ARE NOW OVER 30 OIL AND GAS FIELDS, WITH MANY CONNECTED TO THE MAINLAND BY PIPELINE.

IN EASTERN MALAYSIA, THE SARAWAK AREA, INCLUDING SABAH TO THE

NORTH, CONTAINS OVER A BILLION BARRELS OF PROVEN OIL RESERVES. PRODUCTION HERE DATES BACK TO THE EARLY PART OF THE CENTURY, BUT RECENT EXPLORATION CONTINUES TO UNCOVER SIZEABLE ACCUMULATIONS.

MUCH OF MALAYSIA'S CURRENT PRODUCTION, AND ANY ANTICIPATED FUTURE DEVELOPMENT, IS DIRECTED TOWARDS THE EXPORT MARKET. MALAYSIA'S INTERNAL NEEDS ARE PRINCIPALLY FOR HEAVY FUEL OIL, SO LOWER QUALITY CRUDE IS IMPORTED, FREEING UP MALAYSIA'S HIGH QUALITY CRUDE FOR EXPORT.

THE SARAWAK BASIN GEOLOGICALLY INCLUDES BRUNEI, WHICH IN ITSELF CONTAINS PROVEN RESERVES OF ONE-AND-A-HALF BILLION BARRELS.

(SLIDE 11)

ALSO INDICATED ON THIS SLIDE ARE AREAS OF SIGNIFICANT FUTURE OIL POTENTIAL. INCLUDED ARE THE TWO PRINCIPAL MALAYSIAN BASINS -- PENYU AND SARAWAK. ESTIMATES OF FUTURE OIL POTENTIAL IN THESE AREAS RANGE FROM HALF-A-BILLION TO THREE BILLION BARRELS. HOWEVER, BOTH BASINS ARE IN A MATURE STAGE OF EXPLORATION, SO RESERVE ADDITIONS ARE EXPECTED TO BECOME INCREASINGLY DIFFICULT.

THE MEKONG AND SAIGON BASINS OF VIETNAM MAY ALSO CONTAIN SIGNIFICANT, UNDISCOVERED OIL RESERVES. ALL RECENT ACTIVITY HAS BEEN UNDERTAKEN WITH RUSSIAN ASSISTANCE, AND INFORMATION IS RATHER SPARSE. HOWEVER, THE RUSSIANS ARE REPORTEDLY

CONSTRUCTING TWO PLATFORMS (ONE ALREADY COMPLETED) FOR THE BACH HO FIELD IN THE MEKONG BASIN, NEAR THE SITE OF A SIGNIFICANT DISCOVERY IN THE 1970'S. REPORTED RESERVE ESTIMATES HAVE RANGED AS HIGH AS 2 BILLION BARRELS, WITH INITIAL PRODUCTION, SCHEDULED FOR THIS YEAR, IN THE 50,000 BARREL PER DAY RANGE; HOWEVER, LATER REPORTS HAVE INDICATED MUCH MORE MODEST INITIAL PRODUCTION.

(SLIDE 12)

SHIFTING OUR ATTENTION TO GAS RESOURCES, WE FIRST SHOW CURRENTLY DEVELOPED GAS RESERVES IN THE REGION. IN ADDITION TO INDONESIA'S LARGE RESOURCE BASE, MALAYSIA CONTAINS GIANT DEVELOPED GAS RESERVES IN THE PENYU AND SARAWAK AREAS. PENYU, IN PARTICULAR, IS ESTIMATED TO CONTAIN 30 TCF OF PROVEN GAS. INCREASING QUANTITIES OF GAS PRODUCTION FROM THESE RESERVES ARE NOW PIPELINED ASHORE, FOR BOTH INTERNAL MALAYSIAN CONSUMPTION AND THE SINGAPORE GAS MARKET.

THE GULF OF THAILAND CONTAINS OVER 5 TCF OF PROVEN GAS RESERVES IN 11 GAS-CONDENSATE FIELDS. THE GAS IS TRANSPORTED BY PIPELINE TO THE MAINLAND, WITH CURRENT PRODUCTION IN THE RANGE OF 350 MILLION CUBIC FEET PER DAY, WITH 15,000 BARRELS PER DAY OF ASSOCIATED CONDENSATE.

(SLIDE 13)

IN THE CATEGORY OF UNDEVELOPED GAS, THE LARGEST QUANTITY OUTSIDE

INDONESIA FALLS WITHIN THE PENYU BASIN OF MALAYSIA, WITH AN ESTIMATED 15 TCF OF UNDEVELOPED RESERVES.

OTHER AREAS WORTH NOTING ARE THE GULF OF THAILAND, THE KHORAT PLATEAU OF THAILAND, AND THE MEKONG BASIN OF VIETNAM. THE GULF OF THAILAND CONTAINS ABOUT 5 TCF OF UNDEVELOPED GAS. THE KHORAT PLATEAU BASIN HAS ABOUT ONE-AND-A-HALF TCF OF GAS RESERVES, DISCOVERED WITHIN THE PAST FEW YEARS. AND IN VIETNAM, ALTHOUGH INFORMATION IS SKETCHY, THERE IS A REPORTED ONE TCF OF UNDEVELOPED GAS IN THE MEKONG BASIN.

(SLIDE 14)

LIKE THE REST OF THE PACIFIC RIM, THIS CENTRAL AREA PROBABLY CONTAINS PROLIFIC QUANTITIES OF UNDISCOVERED GAS. OUTSIDE OF INDONESIA, THE LARGEST POTENTIAL FALLS IN MALAYSIA'S PENYU AND SARAWAK BASINS, EACH WITH PREDICTED FUTURES AS HIGH AS 10 TO 15 TCF.

IN THAILAND, THE GULF OF THAILAND AND THE KHORAT PLATEAU MAY EACH CONTAIN FUTURE GAS RESERVES IN THE 2 TO 10 TCF RANGE.

IN SUMMARY, THE CENTRAL AREA CONTAINS VERY SIGNIFICANT GAS RESERVES, MUCH OF WHICH ARE UNDEVELOPED, AND THE POTENTIAL FOR SUBSTANTIAL FUTURE ADDITIONS.

OUTSIDE OF INDONESIA, ALL CURRENT AND NEAR-TERM PLANNED PRODUCTION

IS DESTINED FOR INTERNAL MARKETS, NOT LNG EXPORT. WE CAN ANTICIPATE INCREASING CONVERSION TO GAS FOR DOMESTIC ENERGY NEEDS, FREEING UP OIL AND CONDENSATE FOR THE EXPORT MARKET.

(SLIDE 15)

I WILL NOW ASK YOU TO SHIFT YOUR ATTENTION TO THE SOUTHERN REGION OF THE WESTERN PACIFIC, AND THE PETROLEUM RESOURCES OF AUSTRALIA, NEW ZEALAND, AND PAPUA NEW GUINEA.

THIS SLIDE SHOWS FIRST THE MAJOR CURRENTLY PRODUCING OIL BASINS. BY A WIDE MARGIN, THE LARGEST DISCOVERED OIL RESERVES FALL WITHIN THE GIPPSLAND BASIN UNDER THE BASS STRAITS OF SOUTHERN AUSTRALIA. REMAINING OIL RESERVES IN GIPPSLAND ARE ESTIMATED AT OVER A BILLION BARRELS. PRODUCTION FROM THE GIPPSLAND BASIN FIELDS IS CURRENTLY ABOUT 400,000 BARRELS PER DAY, ACCOUNTING FOR OVER 80 PERCENT OF AUSTRALIA'S TOTAL OIL PRODUCTION. THE BASIN, HOWEVER, IS IN A MATURE STAGE OF EXPLORATION, AND NO MAJOR DISCOVERY HAS BEEN MADE IN RECENT YEARS.

THE EROMANGA AND COOPER BASINS IN THE INTERIOR OF AUSTRALIA CONTAIN TOTAL ESTIMATED RESERVES IN THE 100 MILLION BARREL RANGE, AND ACCOUNT FOR 13 PERCENT OF AUSTRALIA'S OIL PRODUCTION. EXPLORATION HAS BEEN VERY ACTIVE IN THESE BASINS WITHIN THE PAST FEW YEARS, BUT DISCOVERIES HAVE BEEN RELATIVELY MODEST IN SIZE.

BARROW ISLAND FIELD, WITHIN THE BARROW SUB-BASIN OFFSHORE WESTERN AUSTRALIA, CONTRIBUTES 4 PERCENT OF AUSTRALIA'S OIL. THE BARROW AND NEARBY DAMPIER SUB-BASINS CONTAIN OIL AND CONDENSATE RESERVES IN THE RANGE OF SEVERAL HUNDRED MILLION BARRELS. EXPLORATION IS ACTIVE IN THESE BASINS, AND THE POTENTIAL EXISTS FOR SIGNIFICANT ADDITIONS OF CONDENSATE ASSOCIATED WITH MAJOR GAS RESERVES.

THE MOST RECENT AUSTRALIAN OIL PRODUCTION TO COME ON STREAM IS THE JABIRU FIELD IN THE BROWSE BASIN ON THE NORTHWEST SHELF. RESERVES IN JABIRU ARE REPORTED TO BE IN THE 20 TO 40 MILLION BARREL RANGE. THE FIELD WENT ON STREAM LAST MONTH, AND PLANS CALL FOR REACHING PRODUCTION LEVELS OF 13,000 BARRELS PER DAY.

OUTSIDE OF AUSTRALIA, THE ONLY AREA WITH SIGNIFICANT PROVEN LIQUID RESERVES IS THE TARANAKI BASIN OF NEW ZEALAND. THERE IS ONLY MINOR OIL ONSHORE TARANAKI, BUT SUBSTANTIAL QUANTITIES OF CONDENSATE ARE ASSOCIATED WITH MAJOR GAS RESERVES IN THE OFFSHORE BASIN. WE'LL DISCUSS THESE GAS RESERVES LATER.

(SLIDE 16)

FUTURE OIL POTENTIAL IN AUSTRALIA FALLS MAINLY WITHIN THE CURRENTLY PRODUCING BASINS. ONE EXCEPTION IS THE RELATIVELY-UNEXPLORED BONAPARTE GULF BASIN, WHICH, TOGETHER WITH THE BROWSE BASIN, HOLDS SOME PROMISE OF BEING OIL-PRONE.

In addition, substantial condensate reserves will undoubtedly be proven in the Barrow and Dampier Sub-basins, associated with giant Northwest Shelf gas accumulations.

Another area of oil potential that we at Chevron are particularly excited about is the Strickland basin of Papua New Guinea. Chevron, and Gulf before it, have been exploring the mountainous, interior regions of Papua New Guinea for several years. We had some very exciting news earlier this year when our Iagifu-2X wildcat well encountered oil in a thick, high quality reservoir. Delineation drilling is currently in progress, and we are optimistic about the chances of proving-up an economic accumulation, and perhaps, a highly productive trend. Current estimates of future oil potential in the Strickland basin range from half a billion to 2 billion barrels.

(SLIDE 17)

This photograph was taken on one of the concessions that Chevron operates in Papua New Guinea. As you can see, the terrain is mountainous and covered by rain forests. Oil development in this area would require a pipeline to the Gulf of Papua, about 200 miles to the southeast.

(SLIDE 18)

There is also some potential in the southern basins of New

ZEALAND. BOTH THE SOLANDER AND GREAT SOUTH BASINS ARE RELATIVELY UNEXPLORED. THESE AREAS HAVE HARSH OPERATING AND ECONOMIC ENVIRONMENTS, BUT HOLD SOME POSSIBILITY OF MAJOR OIL AND/OR GAS ACCUMULATIONS. THERE IS VERY LITTLE HARD DATA ON WHICH TO BASE OUR EVALUATIONS.

IN SUMMARY, CURRENT OIL PRODUCTION IN THE SOUTHERN REGION FALLS ALMOST ENTIRELY WITHIN AUSTRALIA. THIS PRODUCTION (INCLUDING CONDENSATE AND NATURAL GAS LIQUIDS) AMOUNTS TO A HALF-MILLION BARRELS A DAY, WHICH IS JUST ENOUGH TO KEEP AUSTRALIA SELF-SUFFICIENT IN OIL. THERE IS SOME HOPE OF FUTURE OIL IN NORTHWEST AUSTRALIA, AND, AS MENTIONED, WE ARE OPTIMISTIC ABOUT PAPUA NEW GUINEA. HOWEVER, THE GEOLOGY OF THIS REGION STRONGLY FAVORS GAS, AND WE CAN EXPECT PRINCIPALLY GAS AND ASSOCIATED CONDENSATE DISCOVERIES TO DOMINATE IN THE FUTURE.

(SLIDE 19)

THIS SLIDE SHOWS THE LOCATION OF MAJOR DEVELOPED GAS DISCOVERIES IN THE REGION.

CURRENT GAS PRODUCTION IN AUSTRALIA IS OVER A BILLION CUBIC FEET PER DAY, DIRECTED TOWARD DOMESTIC CONSUMPTION. PRODUCTION IS DOMINATED BY THE THREE BASINS ILLUSTRATED ON THE SLIDE. THE COOPER AND EROMANGA BASINS, WITH RESERVES OF 4 TCF, ACCOUNT FOR 38% OF THE COUNTRY'S PRODUCTION. THE GIPPSLAND BASIN CONTAINS ALMOST 10 TCF, BOTH IN GAS FIELDS AND IN ASSOCIATION WITH OIL

RESERVES. GIPPSLAND ACCOUNTS FOR 36% OF CURRENT AUSTRALIAN GAS PRODUCTION. THE THIRD DOMINANT AREA IS THE DAMPIER SUB-BASIN, WITH BY FAR THE LARGEST RESOURCE BASE; RESERVES DEVELOPED TO DATE, OR CURRENTLY UNDER DEVELOPMENT, ARE ESTIMATED AT OVER 7 TCF.

(SLIDE 20)

I WOULD LIKE TO DISCUSS THE DAMPIER SUB-BASIN IN MORE DETAIL. THIS PHOTOGRAPH SHOWS THE ONSHORE FACILITIES OF THE NORTHWEST SHELF PROJECT, OPERATED BY THE WOODSIDE GROUP, IN THE DAMPIER SUB-BASIN'S RANKIN TREND. THIS IS AUSTRALIA'S LARGEST AND MOST EXPENSIVE NATURAL RESOURCE PROJECT, AND IS GEARED TOWARD DELIVERY OF MAJOR LIQUIFIED GAS RESERVES TO THE JAPANESE MARKET. THE INITIAL STAGE OF THE PROJECT, PROVIDING GAS TO WESTERN AUSTRALIA'S DOMESTIC MARKET, BEGAN OPERATION IN 1984. PHASE I OF THE PROJECT WILL PROVIDE ALMOST 400 MILLION CUBIC FEET OF GAS PER DAY TO WESTERN AUSTRALIA.

PHASE II OF THE PROJECT, CURRENTLY UNDERWAY, WILL PROVIDE EXPORT SALES OF LNG TO JAPANESE MARKETS COMMENCING IN 1989. PLATEAU PRODUCTION WILL REACH 900 MILLION CUBIC FEET PER DAY. OVER THE 19 YEAR LIFE OF THE CONTRACT, THE PROJECT WILL PROVIDE MORE THAN 9 TCF OF GAS THROUGH LNG SHIPMENTS.

(SLIDE 21)

- Outside of Australia, the major developed gas reserves lie in the offshore Taranaki basin of New Zealand. Developed gas reserves in Taranaki total over 5 TCF. In addition to conventional domestic utilization, this gas is also employed in a "synthetic petrol" process to provide a substitute for gasoline. As a result, New Zealand is now 56% self sufficient in transport fuels. The process, however, is extremely costly, and today's lower crude prices allow products to be imported from Singapore at one-third the price of synthetic petrol generation.

(SLIDE 22)

Shown on this slide are the major undeveloped gas reserves of the region. Australia is estimated to contain as much as 30 TCF of undeveloped gas reserves in the Northwest Shelf basins discussed earlier. And this is in addition to approximately 17 TCF of gas discovered in deep water on the Exmouth Plateau of Australia's West Coast, a resource that appears uneconomic for the foreseeable future.

(SLIDE 23)

In terms of future gas, the potential of this southern region is enormous. The largest resource is off the Northwest shelf of Australia, with estimates of future discoveries ranging as high as 50 TCF. Development of future reserves for LNG export

FROM THIS AREA CAN BE EXPECTED WELL INTO THE 21ST CENTURY.

(SLIDE 24)

THIS FINAL SLIDE SHOWS THE RELATIVE DISTRIBUTION OF OIL AND GAS WITHIN ALL THE PACIFIC RIM BASINS DISCUSSED IN THIS TALK. FOR PURPOSES OF COMPARISON, GAS HAS BEEN CONVERTED TO BARRELS OF OIL EQUIVALENT, AND THE RELATIVE DISTRIBUTIONS OF OIL AND GAS HAVE BEEN SHADED GREEN AND RED RESPECTIVELY ON THE ACCOMPANYING PIE DIAGRAMS. FIGURES USED ARE CUMULATIVE TOTALS OF BOTH DISCOVERED RESERVES AND FUTURE POTENTIAL.

THROUGHOUT THIS TALK I HAVE TRIED TO DISCUSS OIL AND GAS SEPARATELY BECAUSE THESE RESOURCES WILL CONTRIBUTE IN SUCH VERY DIFFERENT WAYS TO PETROLEUM MARKETS OF THE FUTURE. IN SPITE OF THE INTENSE EFFORTS OF NATIONAL GOVERNMENTS AND INTERNATIONAL OIL COMPANIES, LIQUID PETROLEUM IS STILL A DWINDLING RESOURCE. MANY GIANT OIL ACCUMULATIONS OF THE PACIFIC RIM ARE AT OR APPROACHING PEAK OFFTAKE, WITH PRODUCTION DECLINES LOOMING ON THE NEAR HORIZON. NEWLY DISCOVERED RESERVES OF ANY SIGNIFICANT PROPORTION ENTER THE DEVELOPMENT PHASE AT THE EARLIEST POSSIBLE DATE.

GAS, ON THE OTHER HAND, IS PRESENT IN ABUNDANT QUANTITIES. A GLANCE AT THE SLIDE WILL SHOW THE DOMINANCE OF GAS IN THE REGION, IN SPITE OF THE FACT THAT OUR EXPLORATION EFFORTS HAVE BEEN DEVOTED PRIMARILY TO FINDING OIL. ON BALANCE, THERE IS

FAR MORE GAS THAN THE REGION'S DOMESTIC MARKETS CAN PRESENTLY ABSORB. WE CAN ANTICIPATE A CONTINUING SCENARIO OF MAJOR ACCUMULATIONS DISCOVERED, OFTEN BY ACCIDENT, AND JOINING THE LONG QUEUE TO AWAIT MARKET DEVELOPMENT. THERE IS CLEARLY AN ENORMOUS RESOURCE FOR THE FUTURE, BUT ONE THAT WON'T BE TAPPED UNTIL THE MARKET PLACE ALLOWS.

IN CLOSING I WOULD LIKE TO BRIEFLY ADDRESS THE CURRENT, DEPRESSED-PRICE ENVIRONMENT FACING THE PETROLEUM INDUSTRY, AND ITS IMPACT ON EXPLORATION AND DEVELOPMENT WORLDWIDE.

THE FIRST SYMPTOM THAT WE NOTICE IS A MARKED DECREASE IN NEWLY-INITIATED DEVELOPMENT PROJECTS FOR BOTH OIL AND GAS. REDUCED OIL PRICES -- OR LNG PRICES DIRECTLY TIED TO OIL -PRECLUDE MANY OF THESE PROJECTS ON SIMPLE ECONOMIC GROUNDS. IN ADDITION, EVEN PROJECTS WITH FAVORABLE ECONOMICS ARE BEING CURTAILED BECAUSE OF CASH FLOW RESTRICTIONS FACING BOTH INDUSTRY AND PARTICIPATING NATIONAL GOVERNMENTS. IN FACT, ALMOST THE ONLY MAJOR PROJECTS NOW BEING INITIATED ARE THOSE THAT HAVE BEEN STRONGLY ENCOURAGED BY HOST GOVERNMENTS -- THROUGH RELAXATION OF TERMS TO IMPROVE THE ECONOMIC RETURN TO INDUSTRY, AND OFTEN IN CONJUNCTION WITH GOVERNMENT INCENTIVES TO ENCOURAGE EARLY DEVELOPMENT.

ON THE EXPLORATION SIDE, WE ARE SEEING A REDUCED, BUT STILL SIZEABLE EFFORT TO FIND LARGE OIL RESERVES WORLDWIDE. THE PACIFIC RIM AREAS DISCUSSED IN THIS TALK FACE SIGNIFICANT PRODUCTION DECLINES IN THE EARLY 1990'S, AND HOPEFULLY ALSO AN OIL PRICE

REBOUND TO MORE ACCEPTABLE LEVELS. TO MEET THIS FUTURE DEMAND, THE OIL INDUSTRY MUST CONTINUE TO ACTIVELY EXPLORE THOSE BASINS THAT HAVE LARGE RESERVE POTENTIAL. EMPHASIS WILL BE ON AREAS WITH LOW TECHNICAL COSTS -- FOR EXAMPLE, PROXIMITY TO MARKET OR EXPORT FACILITIES -- AND ATTRACTIVE GOVERNMENT FISCAL TERMS THAT PROVIDE THE REQUIRED ECONOMIC RETURN. IN SHORT, FOR THE NEXT FEW YEARS WE CAN EXPECT THAT INDUSTRY'S SCARCE EXPLORATION FUNDS, AND EVEN SCARCER DEVELOPMENT FUNDS, WILL BE CHANNELED PREFERENTIALLY TO THOSE AREAS WHERE HOST GOVERNMENTS PROVIDE THE MOST ATTRACTIVE ECONOMIC INCENTIVES.

THANK YOU VERY MUCH.

Japanese Oil and Gas Situation

- Supply and Demand to 1990 -

Address at the International Oil & Gas Markets Conference

Akihiko Nomiyama
Director
Nippon Mining Co.

1. Acknowledgements and introduction

(1) Thank you Mr. Welty for your kind introduction. I wish also to thank the organizers of this conference, namely, the Canadian Energy Research Institute, members of the Calgary Chamber of Commerce and distinguished guests for giving me an opportunity to speak to this important assembly.

(2) I am Akihiko Nomiyama of Nippon Mining Co. Nippon Mining, which is one of the most important resources corporations of Japan, had its early beginnings in the mining and refining of nonferrous metals. We have also engaged in the developing and refining of petroleum and gas resources since before World War II. Most recently, we have moved into metal fabrication as well as the field of "new materials", which include electronic materials and biotechnology. Our current operations span the entire range of resources and energy.

At Nippon Mining, I am in charge of the petroleum group. All oil sales are carried out by Kyodo Oil Co., an affiliated company which is our primary distributor. K.O.C. has a 12% market share of petroleum products in Japan. This means we are involved in the oil industry in all aspects; from development through marketing.

(3) Today, I wish to assess the supply-demand situation for oil in Japan from the viewpoint of a private petroleum company.

2. The position of Japan in the oil and gas market of the Pacific Rim region

(1) Before taking up the oil situation in Japan, I wish first to deal with how Japan is placed in the oil market of the Pacific Rim region.

(2) Chart 1. This chart shows trends in the demand for oil in the Pacific Rim region by area. In 1984, the demand for oil for the entire region was about 8 million B/D, of which 3.2 million B/D, or about 40%, was consumed by Japan. While the demand for oil in Japan is decreasing, that in other areas is steadily rising along with their economic development. Japan's demand for oil is expected to decline to about 30% of the total in this area in 1990.

(3) The fact remains, however, that Japan is still the largest market for oil in the Pacific Rim region. Thus, an analytical study of trends in the Japanese market would be an important factor in anticipating future oil-flow in this region.

3. Demand for primary energy in Japan

(1) Chart 2. Japan's demand for primary energy rose rapidly at a rate of more than 10% annually from 1955 until just before the oil crisis. In 1975, the figure reached 3,660 trillion (10^{12}) kcal. Since then, with the change to energy efficient manufacturing, the annual rate of demand, which had been increasing steadily has leveled off. In 1984, primary energy demand was 4,000 trillion (10^{12}) kcal.

(2) Of the total primary energy demand, oil's share has been the largest since 1962. On the eve of the first oil crisis of 1973, it peaked at 78%. Since then, the rate of increase in total energy demand has steadily declined. Meanwhile, conversion to alternative engergy has progressed apace in industry, resulting in a major decline in the demand for oil. Consequently, oil's share of the total energy demand fell to 58% in 1984 and is anticipated to drop below the 50% mark over the next 10 years.

(3) Meanwhile, mirroring an extensive national policy to diversify sources of energy, the use of nuclear power and natural gas has rapidly expanded. These two forms of energy are expected to play a major role in filling the expanded demand for energy. In this sense, it is a matter of primary concern to us that Japan obtains most of her natural gas from sources in the Pacific region. We are vitally interested in securing an inexpensive and stable supply of this form of energy.

4. Japan's demand for oil

(1) Chart 3. Japan's demand for oil hit a peak of 4.05 million B/D in 1978. After that, it steadily declined until it dropped in 1985 to 3.12 million B/D. During this period, demand for gasoline and middle distillates steadily increased, while that for residues drastically decreased. The demand structure rapidly shifted towards lighter distillates. Gasoline and middle distillate demand rose from 47% of the total demand in 1970 to 75% in 1985.

(2) The sharp drop in the price of oil from the beginning of this year is likely to bring about a revival in the demand for oil in Japanese industry. The situation is still fluid. However, when this recovery in demand is discounted, demand for oil as a whole is expected to level off and probably decline slightly in the next few years.

(3) The renewed demand for oil is contingent upon confidence in a stable price for oil. If it seems that the price of crude oil in the medium term will stabilize at a few dollars over $10, in terms of 1985 dollars, there is a possibility that demand could recover by up to 100,000 B/D on the entire Japanese market. It will take time to restore users' confidence in the reliability of oil. In reality, there are few indications that this confidence is being restored. However, as data on demand is accumulated in the months ahead, a qualitative prognosis in this area will become possible.

(4) Chart 4. Now I would like you to look at this chart showing data used to predict demand for oil in Japan. The chart shows trends in Japan's demand for energy sector by sector. In addition to active investments by Japanese industry in energy efficiency, a shift in the industrial structure has been taking place from energy-intensive industries towards industries less dependent on energy. The correlation between demand for industrial energy and economic activities has weakened, and thus the demand for industrial energy is leaning toward a further decline. The demand of energy for transportation and household use, however, is still closely related to economic growth. Therefore, even without taking into consideration the impact of the recent drop in oil prices, demand of oil for transportation and household use is expected to continue to rise at a steady pace. As energy for small-size transport engines in particular, oil enjoys a position of absolute superiority. I am convinced that the demand for oil in this area will remain firm for a fairly long period.

5. Japan's imports of crude oil and gas

(1) Chart 5. This shows trends in Japan's imports of crude oil. The volume peaked at 4.7 million B/D in 1977, but sharply decreased due to a drastic decline in the demand for oil after 1980, and dropped to 3.4 million B/D in 1985.

(2) A characteristic of this period was a diversification in the sources of crude oil. The share of crude oil imports from the Pacific Rim region rose steadily to 25% in 1985 from 13% in 1970.

(3) Total crude oil imports are likely to either remain unchanged at 3.2 to 3.4 million B/D or even decline slightly. Imports from the Pacific region are expected to remain stable at more than one fourth of the total. Needless to say, crude oil trading is conducted on a commercial basis. Therefore, the choice of crude oil sources will be very much subject to economic conditions. There is room for expansion of imports of crude oil from the Pacific Rim region, however, if full advantage can be taken of the economy of the short distances involved, and the safety of the region.

(4) Chart 6. This chart shows imports of natural gas, which began with the electric power and city gas industries in 1970. As you can see, these volumes rose sharply after 1977. As the chart indicates, the Pacific Rim region accounts for a significant portion of the imported natural gas, comprising as much as 88% of the total in 1985.

(5) As I said at the outset, the increase of energy demand in Japan in the years to come will depend to some degree on the anticipated expansion of the import volume of natural gas. For this reason, we are counting on the Pacific Rim region, with its large deposits of natural gas.

(6) The present low price of oil, however, is likely to have a major impact, even on the future of natural gas. In the selection of forms of energy, economic merit is the crucial determinant. In this sense, I believe, ways ought to be studied to make the price of natural gas more elastic. This, I believe, is a task that needs to be tackled to ensure a smooth flow of energy in the Pacific Rim region and to determine the best possible selection of energy sources for the future.

6. Japan's oil product supply situation

(1) Chart 7. The total oil product supply for Japan, including petroleum gas, for the first half of 1986 was 3.9 million B/D, of which 20% was imported.

(2) In 1975, import products accounted for 10% of the total supply of 4.4 million B/D. Although in subsequent years, domestic demand for oil has declined, imports, principally of naphtha, have expanded, raising their share of the total.

(3) As is well known, Japan opened up its domestic market in January of this year to the import of gasoline, kerosene (heating oil) and gas oil, in addition to naphtha and fuel oil which was already being imported. This liberalization was carried out in the spirit of international cooperation and in view of the important international position Japan holds. From now on, we can look forward to an expansion in foreign trade, which has economic merit to take careof the necessary adjustments to supply and demand relationships.

(4) The reason for this is that, first of all, demand for oil in general has decreased, and its relationship with economic growth, primarily in terms of industrial demand, has weakened. This means that the impact of such transient factors as weather and temperature has become relatively greater. Also, the fact that today we are more subject to instability in the international oil market than before is diminishing production's flexibility in adjusting to supply and demand. Therefore, increasing the amount of supplemental import/export adjustments makes good economic sense.

(5) Thus, there is a good chance that the percentage of imports in Japan's supply of oil products is likely to expand. Of course, a major criterion for deciding between production and import for us, as an oil company, is economic merit. However, our business environment does suggest a good possibility of a larger percentage of imports in the total volume.

7. Japan's role in the oil and gas market in the Pacific Rim region

(1) I have so far described the oil situation, particularly the quantitative aspect of the supply and demand for oil in Japan. Japan's oil supply and demand may be said to have a great impact on oil flow in the Pacific Rim region.
For this reason, I wish to make a few personal observations.

(2) As an officer of a Japanese oil company, I believe it is necessary for Japan to carry out her business with a view to helping to smooth the flow of oil not only in the Pacific Rim region, but in the Free World as a whole, rather than balancing supply and demand only in Japan. By making good use of her sophisticated refinery facilities, Japan can play a supporting role in helping to reduce short-term seasonal supply and demand fluctuations in the Pacific Rim region. In fact, it is possible for Japan to function effectively as one of the major oil terminals in the Pacific Rim region.

(3) I believe Japan, as a major consumer of oil, has an international responsibility to shoulder a fair share of the risk involved in the development of oil resources in Pacific Rim region, in order to raise the percentage of crude oil from this region used to supply her own needs. Japan has taken positive action in this regard, primarily through the Japan National Oil Corporation. From this point onward, I believe we should seek new development along these lines by actively exchanging information in the private sector as well.

8. Conclusions

(1) To sum up, I have touched upon many issues. I believe we should try to find out what kind of oil industry and policy we should develop to be able to best contribute to the development of the Pacific Rim by smoothing the distribution patterns of oil in this region.

(2) If we are to do this, I believe we must have much closer relations with the oil companies of other countries, strengthened through the exchange of information and the establishment of better lines of communication. I would like to ask you to feel free to contact me with your own ideas, suggestions, or propositions that would involve Japanese oil companies.

Thank you.

NOTES FOR AN ADDRESS

BY

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TO

CANADIAN ENERGY RESEARCH INSTITUTE
OIL AND GAS CONFERENCE

SEPTEMBER 16, 1986
CALGARY, ALBERTA

I AM DELIGHTED TO HAVE THE OPPORTUNITY TO DISCUSS THE STATE OF NATURAL GAS DEREGULATION WITH YOU TODAY. I WILL COMMENT ON THE PRINCIPLES OF GAS DEREGULATION WHICH THE CANADIAN PETROLEUM ASSOCIATION HAS ESPOUSED FOR A NUMBER OF YEARS, AND THE STATUS OF THAT DEREGULATION TODAY, TEN MONTHS AFTER THE NEW GAS POLICY WAS ANNOUNCED. AS YOU WILL SEE, DURING THE NEXT SIX WEEKS CANADA'S NATURAL GAS POLICY-MAKERS HAVE SOME MAJOR ISSUES TO ADDRESS.

FROM THE VIEWPOINT OF ECONOMIC PRINCIPLE, IT IS WORTH NOTING THAT, ALTHOUGH THE NATURAL GAS INDUSTRY HAS BEEN FULLY REGULATED FOR A DECADE, THE MARKETS IN THE EARLY YEARS OF COMPLETE REGULATION WERE NOT CHARACTERIZED BY THE SURPLUS GAS SUPPLIES AND CORRESPONDINGLY FIERCE COMPETITION THAT EXISTS TODAY. THE CHANGED ENVIRONMENT HAS NOT ONLY MADE REGULATION UNDESIRABLE. IT HAS ALSO MADE IT IMPRACTICAL.

DURING THE PERIOD IN WHICH THE NATIONAL ENERGY PROGRAM WAS IN FORCE, THE CPA RECOGNIZED THAT THAT POLICY WOULD SOON COLLAPSE UNDER ITS OWN WEIGHT. DURING THOSE YEARS WE BEGAN TO DEVELOP WHAT WE CALLED OUR ALTERNATE ENERGY POLICY, A COMPREHENSIVE SET OF POLICIES WHICH WE FELT WOULD MEET THE NEEDS OF ALL

THOSE WITH A STAKE IN THE PETROLEUM INDUSTRY. ONE OF OUR KEY CONCERNS, OF COURSE, WAS TO DEVELOP A NATURAL GAS POLICY SUITABLE TO RAPIDLY CHANGING MARKETS. OF PARTICULAR IMPORTANCE, WE FELT THAT THE NEW POLICY SHOULD LARGELY REPLACE THE MORIBUND REGULATORY FRAMEWORK.

ON THE MATTER OF REGULATION, OUR PROPOSALS INCLUDED THE FOLLOWING STATEMENT. I QUOTE:

"THIS INDUSTRY HAS NO ARGUMENT WITH REGULATION PER SE. WHEN APPROPRIATE AND WELL-WRITTEN, (REGULATION) PROVIDES CLEAR GROUND-RULES FOR BUSINESS ACTIVITIES. HOWEVER, PROBLEMS ARISE WHEN REGULATIONS ARE INAPPROPRIATE, UNCLEAR, UNNECESSARY OR REQUIRE ONEROUS COMPLIANCE PROCEDURES. ALL THESE PROBLEMS EXIST IN THE OVER-REGULATED OIL AND GAS INDUSTRY, AND HAVE SERIOUS CONSEQUENCES." UNQUOTE.

AND WITH RESPECT TO NATURAL GAS PRICES, OUR ALTERNATE ENERGY POLICY SAID, AND I QUOTE:

"CANADIAN NATURAL GAS PRICES ARE CURRENTLY SET BY GOVERNMENTS. THIS APPROACH LACKS THE FLEXIBILITY TO COPE WITH CHANGING MARKET CONDITIONS AND SHOULD BE

ALTERED. HOWEVER, GAS MARKETING STRUCTURES ARE EXTREMELY COMPLEX, INVOLVING FIELD PROCESSING BY PRODUCERS, TRANSMISSION BY MAJOR CARRIERS AND MARKET DISTRIBUTION BY REGULATED PUBLIC UTILITIES. LONG-TERM CONTRACTS AMONG THE THREE PARTIES ALLOW FOR AMORTIZATION OF EXPENSIVE PROCESSING AND TRANSMISSION FACILITIES. CHANGING THE PRESENT APPROACH WILL THEREFORE BE A LENGTHY AND COMPLEX PROCESS, YET THE CPA BELIEVES THAT NATURAL GAS, LIKE CRUDE OIL, SHOULD BE PRICED BY COMPETITIVE MARKET FORCES RATHER THAN BY REGULATION. THE RESULT WOULD BE GREATER EFFICIENCY IN PRODUCTION, TRANSPORTATION, DISTRIBUTION AND CONSUMPTION BECAUSE INVESTMENT DECISIONS WOULD BE MORE SOLIDLY BASED ON ECONOMIC FACTORS. THERE WOULD ALSO BE INCREASED SALES OPPORTUNITIES, THROUGH MORE EFFECTIVE COMPETITION WITH OTHER ENERGY FORMS." UNQUOTE.

THESE PRINCIPLES CLEARLY ARTICULATED OUR POSITIONS AT THAT TIME, AND THE THREE YEARS THAT HAVE PASSED SINCE WE PENNED THOSE WORDS HAVE ONLY UNDERSCORED THEIR RELEVANCE. AS YOU ARE AWARE, OUR ALTERNATE ENERGY POLICY ANTICIPATED A CHANGE IN GOVERNMENT AT THE FEDERAL LEVEL. AFTER THEIR ELECTION IN 1984, THE NEW CONSERVATIVE GOVERNMENT MOVED QUICKLY TO CHANGE

CANADA'S ENERGY POLICIES. WITHIN SIX MONTHS OF TAKING OFFICE THEY AND THEIR PROVINCIAL COUNTERPARTS IN WESTERN CANADA HAD SIGNED THE WESTERN ACCORD. SIX MONTHS LATER THE FOUR GOVERNMENTS HAD PUT FORWARD THEIR AGREEMENT ON NATURAL GAS PRICES AND MARKETING. BETWEEN THEM, THOSE POLICIES ADOPTED MOST OF THE RECOMMENDATIONS ON CONVENTIONAL OIL AND GAS THAT WE PUT FORWARD IN OUR ALTERNATIVE ENERGY POLICY.

BECAUSE OF THE COMPLEXITY OF THE NATURAL GAS INDUSTRY, THE PROCESS OF DEREGULATING THAT PART OF THE BUSINESS HAS BEEN LONG AND ARDUOUS. NONETHELESS, MUCH OF THE JOB HAS ALREADY BEEN DONE. FOR EXAMPLE, ABOUT 400 BILLION CUBIC FEET OR 35 PER CENT OF THE EASTERN CANADIAN MARKET IS BEING SERVED BY RENEGOTIATED PRICES UNDER DIRECT SALES OR COMPETITIVE MARKETING PROGRAMS (CMPS) PUT IN PLACE SINCE NOVEMBER 1985.

THERE HAS ALSO BEEN A FLURRY OF ACTIVITY BY GOVERNMENT AGENCIES TO RECEIVE VIEWS AND PROVIDE DECISIONS ON WAYS TO IMPLEMENT THE PROCESS. IN ADDITION, ONTARIO AND QUEBEC HAVE ISSUED DECISIONS ON THE IMPORTANT MATTER OF CONTRACT CARRIAGE.

THE NATIONAL ENERGY BOARD (NEB) HAS REACHED SEVERAL DECISIONS, SOME OF WHICH REMAIN THE FOCUS OF ATTENTION AS WE SEEK TO MEET THE TARGET DATE OF NOVEMBER 1, 1986. I WOULD NOW LIKE TO OUTLINE THE CPA POSITION ON SEVERAL ISSUES WHICH REMAIN TO BE RESOLVED AS WE STRIVE TOWARD A DEREGULATED ENVIRONMENT WHICH WILL BALANCE THE INTERESTS OF ALL PLAYERS.

IN A NUTSHELL, THE DEREGULATED NATURAL GAS INDUSTRY WHICH WE ARE MOVING TOWARD CAN BE CHARACTERIZED IN THREE WAYS. FIRST, IT IS ONE IN WHICH THERE ARE MULTIPLE BUYERS AND SELLERS. SECOND, IT IS ONE IN WHICH WHOLESALE GAS PRICES ARE DETERMINED BY NEGOTIATION BETWEEN BUYERS AND SELLERS, FREE OF REGULATION. FINALLY, IT IS ONE IN WHICH THE TRANSPORTATION SYSTEM PROVIDES FOR OPEN AND NON-DISCRIMINATORY ACCESS FOR ALL SHIPPERS. IN THE BROAD SENSE, THEREFORE, THE PRESENT NATURAL GAS ENVIRONMENT IS BEGINNING TO MOVE TOWARDS THE ECONOMISTS' THEORETICAL CONCEPT OF PERFECT COMPETITION.

FROM THE INDUSTRY'S PERSPECTIVE, HOWEVER, SEVERAL FUNDAMENTAL PRINCIPLES MUST STILL BE ADDRESSED DURING

THE PROCESS OF DEREGULATION. AND THEY CAN ONLY BE RESOLVED WITH CONSIDERABLE DISCUSSION AND POLITICAL WILL.

TO BEGIN WITH, MUCH OF THE GAS NOW DISCOVERED AND DEVELOPED HAS BEEN COMMITTED UNDER LONG-TERM CONTRACTS TO FIVE MAJOR CARRIERS: TRANSCANADA, WESTCOAST, PROGAS, PANALBERTA AND ALBERTA AND SOUTHERN. EACH OF THESE CARRIERS IS SHIPPING GAS UNDER CONTRACTS SIGNED IN LARGE PART DURING REGULATION, AND THUS DURING A PERIOD IN WHICH MARKET CONDITIONS WERE RADICALLY DIFFERENT FROM THOSE PREVAILING TODAY.

AS WE MOVE TO MARKET-ORIENTED PRICES, WE MUST RESOLVE THE CONFLICT THAT IS ARISING BETWEEN THE NEED TO MAINTAIN THE SANCTITY OF CONTRACT AND THE NEED TO MAKE SIGNIFICANT CHANGES TO A COMPLEX SYSTEM UPON WHICH MANY OF THE CONTRACTS ARE BASED. THE PROBLEM EXISTS BECAUSE MOST OF THE LONG-TERM CONTRACTS SIGNED PRIOR TO THIS YEAR PROVIDE FOR PRICES SET BY GOVERNMENT OR -- IN THE CASE OF CONTRACTS SIGNED PRIOR TO 1975 -- FOR PRICES FIXED IN THE CONTRACT AT THE WELLHEAD OR AT THE PLANT GATE. NEITHER OF THESE ARRANGEMENTS IS SUITABLE IN THE NEW ENVIRONMENT, AND

PRODUCERS ARE RENEGOTIATING THEIR CONTRACTS AS BEST THEY CAN.

AN IMPORTANT PART OF THE NEW NATURAL GAS POLICY WAS ITS UNDERTAKING THAT THE NATIONAL ENERGY BOARD AND THE PROVINCES WOULD REVIEW THE SURPLUS TESTS WHICH GOVERN EXPORT OF GAS FROM CANADA AND FROM THE PROVINCES. ACCORDING TO LAST OCTOBER'S ANNOUNCEMENT, THE GOVERNMENTS INVOLVED EXPECTED THESE REVIEWS TO "RESULT IN SIGNIFICANT ACCESS TO DOMESTIC AND EXPORT MARKETS" AND THUS TO CONTRIBUTE TO THE ACHIEVEMENT OF A MARKET-ORIENTED PRICING SYSTEM. AT THE FEDERAL LEVEL, HOWEVER, THE NEB'S REVIEW OF ITS SURPLUS TEST DID NOTHING BUT REPLACE ONE BAD TEST WITH ANOTHER. NOT ONLY DOES THE NEW TEST PROMISE TO BE MORE BUREAUCRATIC THAN THE LAST, BUT IN OUR VIEW TO AN EXTENT IT ACTUALLY SUBVERTS THE REGULATORY IDEAL. WE HAVE REPEATEDLY EXPRESSED THE OPINION TO GOVERNMENT THAT THE IDEAL SITUATION SHOULD BE TO HAVE NO TEST AT ALL. PARTIES SHOULD BE PREPARED TO CONTRACT FOR THEIR OWN FUTURE USE. BARRING THAT PROSPECT, A NEW TEST SHOULD AT LEAST BE SIMPLE.

I HAVE USED STRONG WORDS HERE, SO LET ME ELABORATE A BIT. THE EXISTENCE OF ANY TEST CREATES AN UNFAIR

DISADVANTAGE FOR GAS PRODUCERS BY REQUIRING THEM TO DEVELOP INVENTORIES WHICH OTHER KINDS OF ENERGY SUPPLIERS NEED NOT DEVELOP.

GAS PRODUCERS UNDERSTAND THE NEED TO PROVIDE FOR FUTURE CANADIAN GAS REQUIREMENTS; THAT IS, AFTER ALL, THEIR BUSINESS. BUT WE BELIEVE THIS SHOULD BE ACHIEVED BY CONTRACTING PRACTICE. THE NEB'S RECENT DECISION AND SURPLUS TEST WE BELIEVE IS MORE CONSTRAINING AND WILL ACTUALLY RESULT IN A LOWER EXPLORATION EFFORT.

WE NEED REGULATION AND PROCEDURES WHICH WILL ENCOURAGE RATHER THAN INHIBIT THE REPLACEMENT OF RESERVES. MARKET ACCESS IS FUNDAMENTAL AS A STIMULUS TO GAS EXPLORATION. A TEST WHICH FURTHER INHIBITS ACCESS TO THE EXPORT MARKET DEFEATS THE PURPOSE OF PROVIDING PROTECTION TO CANADIAN CONSUMERS. THE TEST IN ITSELF DOES NOT GUARANTEE DEVELOPMENT OF SUPPLY FOR CANADA. INSTEAD, IT GUARANTEES A CONSTRAINT ON THE EXPORT MARKET. AND SINCE THAT CONSTRAINT IS BEYOND THE REASONABLE REQUIREMENTS OF A MARKET COMPETITIVE SYSTEM, IT BECOMES SELF DEFEATING.

THE SURPLUS TEST WORKS AGAINST THE GOAL IT IS TRYING TO ACHIEVE BY REQUIRING THE INDUSTRY TO MAINTAIN LARGE VOLUMES OF GAS WHICH ARE NEITHER UNDER CONTRACT NOR FREE TO BE SOLD IN ALTERNATIVE EXPORT MARKETS. IT LEAVES AN ONEROUS OBLIGATION ON PRODUCERS TO MAINTAIN A LARGE GAS INVENTORY, AND AT THE SAME TIME CREATES A SUBSTANTIAL SUPPLY CUSHION FOR CONSUMERS TO POINT TO WHEN NEGOTIATING PRICES.

ANOTHER PROVISION IN THE PRESENT GAS POLICY IS ALSO CONTRARY TO THE WORKINGS OF A FREE MARKET. THAT IS THE SO-CALLED EXPORT FLOOR PRICE TEST, WHICH IS DESIGNED TO PREVENT PRODUCERS FROM SELLING GAS TO U.S. PURCHASERS FOR LESS THAN IT CAN OBTAIN IN ADJACENT MARKETS IN CANADA. THIS SYSTEM, WHICH IS MOTIVATED BY POLITICS RATHER THAN BY SOUND ECONOMIC THINKING, SHOULD BE ELIMINATED.

IN MY VIEW, IT SHOULD BE ELIMINATED FOR FOUR REASONS. FIRST, IT LIMITS ACCESS TO U.S. MARKETS BY RESTRICTING THE SELLER'S MANEUVERABILITY. SECOND, IT FOCUSES ATTENTION ON PRICE TO THE EXCLUSION OF OTHER SIGNIFICANT CONTRACTURAL TERMS -- SUCH TERMS AS RATE OF TAKE, LOAD FACTOR AND SPOT VERSUS TERM TRANSACTIONS. THIRD, IT MAY PREVENT BOTH PRODUCER

AND RESOURCE OWNER FROM OBTAINING FULL MARKET VALUE FOR THE COMMODITY. AND FINALLY, REQUIRING THE CANADIAN PRICE TO BE NO HIGHER THAN THE EXPORT PRICE COULD HAVE THE EFFECT OF RATCHETING DOWN EXPORT PRICES. AFTER ALL, U.S. CONSUMERS ARE LIKELY TO INSIST THAT THEY PAY NO MORE THAN THE PRICE CONSUMERS PAY IN NEARBY CANADIAN MARKETS. U.S. CUSTOMERS FARTHER AFIELD COULD THEN INSIST ON PAYING NO MORE THAN THE PRICE CONSUMERS PAY IN THE NEARBY U.S. MARKETS, AND SO ON.

THIS IS CLEARLY CONTRARY TO THE PRINCIPLE THAT IN A DEREGULATED ENVIRONMENT, BOTH PRICES AND SUPPLY SHOULD BE ESSENTIALLY INVISIBLE. THEY SHOULD CERTAINLY NOT BE MATTERS OF POLITICAL GRANDSTANDING. AND YET BOTH THE SURPLUS TEST AND THE EXPORT FLOOR PRICE TEST LEND THEMSELVES TO THAT KIND OF ACTIVITY.

COMPOUNDING THE CONTRACTED SUPPLY PROBLEM IS THE TAKE-OR-PAY SITUATION ASSOCIATED WITH TRANSCANADA'S GAS SUPPLY. THE HEAVY TAKE-OR-PAY LOAD ON TRANSCANADA LED TO THAT COMPANY'S TOPGAS ARRANGEMENTS OF 1983, BY WHICH MOST PRODUCERS AGREED TO REFINANCING OF TRANSCANADA'S TAKE-OR-PAY COMMITMENTS. UNDER TOPGAS, TCPL'S SYSTEM PRODUCERS

ARE BEARING THE INTEREST COSTS OF THE TOPGAS PAYMENTS AT THE RATE OF 20 CENTS PER THOUSAND CUBIC FEET OF GAS SHIPPED, AND REPAYING THE PRINCIPLE BY DELIVERING 10 PER CENT OF THE PREPAID VOLUMES EACH YEAR.

WITH SOME GAS PRODUCERS NOW ABLE TO BYPASS THE TRADITIONAL TCPL SUPPLY CHAIN AND DEAL DIRECTLY WITH END USERS AND UTILITIES, TCPL'S TOPGAS PLAN COULD BE JEOPARDIZED IF THERE IS A SIZEABLE EROSION OF TCPL'S MARKET. THIS KIND OF EROSION IS QUITE POSSIBLE SINCE PRODUCERS SELLING DIRECTLY HAVE A 20 CENTS PER THOUSAND CUBIC FEET ADVANTAGE OVER COMPETITORS WHO SIGNED ONTO THE TOPGAS SCHEME. IT IS OUR VIEW THAT ALL USERS OF THE TCPL SYSTEM SHOULD PAY THEIR SHARE OF THE INTEREST COST, WHICH IS PART OF THE COST OF HAVING THE TCPL SYSTEM IN PLACE AND AVAILABLE. THE ALBERTA GOVERNMENT RECENTLY INTRODUCED LEGISLATION ON TAKE OR PAY COST SHARING WHICH WILL PROVIDE A MEANS WITHIN ALBERTA TO ACHIEVE A MORE EQUITABLE SHARING.

THE NATIONAL ENERGY BOARD ALSO ADDRESSED THE IMPORTANT AND COMPLEX ISSUE OF WHAT IS COMMONLY KNOWN AS "DEMAND CHARGE TRANSFER."

AS I STATED EARLIER, THE NATURAL GAS INDUSTRY HAS BEEN BUILT ON LONG-TERM CONTRACTS. UPSTREAM, THERE ARE PRODUCER/TCPL RESERVES BASED CONTRACTS; DOWNSTREAM, DISTRIBUTOR/TCPL.CD CONTRACTS. THE HEART OF THE PROBLEM ARISES WHEN A DIRECT SALE MADE IN A DISTRIBUTOR'S FRANCHISE AREA DISPLACES A CORRESPONDING VOLUME OF GAS FROM SALES BY THE DISTRIBUTOR AND HENCE TCPL PRODUCERS. WHILE NOBODY DISPUTES THE PRINCIPLE THAT WHEN THIS OCCURS DISTRIBUTORS SHOULD BE RELEASED FROM THEIR OBLIGATIONS TO THIS EXTENT, AN NEB DECISION ON THE MATTER DID NOT MAKE CLEAR WHETHER THIS RELEASE FROM OBLIGATIONS WOULD BE FOR THE TERM OF THE DIRECT SALE OR PERMANENT.

WE BELIEVE THE RELIEF SHOULD BE PERMANENT AND THAT TCPL AND ITS SUPPLIERS SHOULD NOT BE IN THE POSITION OF "STANDING BY" IN THE EVENT THE DIRECT SALES CUSTOMER RETURNS TO THE DISTRIBUTOR IN THE FUTURE. PERMANENT RELEASE WILL ENABLE TCPL TO REMARKET THOSE VOLUMES LOST THROUGH DIRECT SALE. AS YOU CAN SEE, THIS ISSUE IS AN INTEGRAL PART OF MARKET ACCESS AND EQUITABLE TREATMENT FOR ALL PARTICIPANTS.

A POLITICAL ISSUE WHICH IS CONSIDERABLY MORE CIRCUMSPECT BUT NONETHELESS DAMAGING IS THE MATTER OF PROVINCIAL TAXATION ON NATURAL GAS. IN RECENT MONTHS BOTH QUEBEC AND MANITOBA HAVE IMPOSED TAXES ON NATURAL GAS. QUEBEC'S 8 PER CENT TAX IS PARTICULARLY SERIOUS, SINCE THE QUEBEC MARKET BEYOND MONTREAL WAS UNECONOMIC IN THE FIRST PLACE. IT WAS ONLY DEVELOPED WITH THE HELP OF LARGE-SCALE PRODUCER AND FEDERAL GOVERNMENT SUBSIDIES. REINTRODUCING THAT TAX WILL MAKE IT EVEN HARDER FOR GAS TO COMPETE IN THAT MARKET.

IN THE CASE OF MANITOBA, THAT PROVINCE'S MOTOR FUEL TAX WILL ADD A FURTHER $10 MILLION PER YEAR COST TO THE TRANSCANADA SYSTEM, AND THAT COST WILL BE PAID BY ALL USERS.

ALTHOUGH I HAVE TAKEN A FEW SWIPES AT POLITICAL GRANDSTANDING AND A FEW INSTANCES IN WHICH POLITICS HAS PREVAILED OVER ECONOMICS, I MUST STRESS THAT WE RECOGNIZE THAT CANADA'S NATURAL GAS POLICY-MAKERS ARE VIGOROUSLY PURSUING DEREGULATION. THE MOVE TOWARD FREE MARKETS IS LAUDATORY. THE NEED TO DEVELOP A SYSTEM WHICH BALANCES THE BENEFITS TO PRODUCERS AND CONSUMERS IS ESSENTIAL. IT IS ALSO A MAJOR CHALLENGE.

BECAUSE THE INDUSTRY HAS BEEN SO STRINGENTLY REGULATED FOR SO MANY YEARS, IT IS ACTUALLY REMARKABLE THAT WE HAVE PROGRESSED SO FAR SO QUICKLY IN THE TRANSITION PERIOD. THERE ARE PROBLEMS, HOWEVER, AND SERIOUS CONCERNS WHICH WE IN THE CPA SHARE. BRIEFLY, THEY ARE FIVE:

- FIRST, IN THE MATTER OF EXISTING CONTRACTS, PRODUCERS AND TCPL AND UTILITIES AND TCPL MUST NEGOTIATE CONTRACTS WHICH FIT THE NEW ENVIRONMENT.

- SECOND, THERE SHOULD BE NO EXPORT FLOOR PRICE. THE MARKET AND THE MARKET ALONE SHOULD DETERMINE PRICES AND OTHER TERMS OF SALE.

- THIRD, THE NEB'S SURPLUS TESTS SHOULD BE RELEGATED TO HISTORY. THAT SYSTEM PLACES UNNECESSARY BURDENS ON PRODUCERS, AND IS BETTER DEALT WITH THROUGH THE PROVISIONS OF NATURAL GAS CONTRACTS.

- FOURTH, DISPLACED CONTRACT DEMAND VOLUMES MUST BE RELEASED PERMANENTLY TO GIVE TCPL PRODUCERS THE FAIR OPPORTUNITY TO MARKET GAS ELSEWHERE.

- FIFTH, THE ISSUE OF PAYING TOPGAS SERVICE CHARGES MUST BE RESOLVED IN AN EQUITABLE WAY.

- FINALLY, THERE IS THE MATTER OF PROVINCIAL TAXES ON NATURAL GAS. I CAN OFFER NO SOLUTION TO THIS PROBLEM, SINCE THE PROVINCES ARE WITHIN THEIR RIGHTS IN TAXING THE COMMODITY. I ONLY HOPE THAT IF WE VOICE THE PROBLEM CLEARLY, PROVINCIAL POLICY-MAKERS WILL SEE THE ERROR OF THEIR WAYS AND ROLL BACK OR ELIMINATE THE TAXES.

THAT, LADIES AND GENTLEMEN, SUMMARIZES SOME OF THE PROBLEM ISSUES WE NOW FACE. BUT TO CLOSE ON A POSITIVE NOTE, LET ME REMIND YOU THAT WE HAVE BEGUN TO ENTER AN IMPORTANT NEW ERA FOR THE NATURAL GAS BUSINESS. AND AS WE RIGHTLY FORESAW IN OUR ALTERNATE ENERGY POLICY JUST A FEW SHORT YEARS AGO, THAT ERA IS ONE WHICH WILL BE CHARACTERIZED BY GREATER EFFICIENCY IN PRODUCTION, TRANSPORTATION, DISTRIBUTION AND CONSUMPTION. IT IS ALSO ONE IN WHICH THERE ARE GREATER SALES OPPORTUNITIES, BECAUSE NATURAL GAS IS COMPETING MORE EFFECTIVELY WITH OTHER ENERGY FORMS. THESE ARE IMPORTANT DEVELOPMENTS FOR PRODUCERS, TRANSPORTERS AND CONSUMERS, AND THEY SHOULD BE WARMLY WELCOMED BY ALL OF US.

WE IN THE GAS INDUSTRY ARE RAPIDLY COMING TO ACCEPT THE FUNDAMENTAL CHANGES WHICH HAVE TAKEN PLACE IN OUR BUSINESS. TO A LARGE EXTENT THESE CHANGES HAVE OCCURRED BECAUSE OF INCREASING RECOGNITION THAT NATURAL GAS IS A COMMODITY WHICH MUST COMPETE IN MARKETS INFLUENCED BY GLOBAL FACTORS, NOT JUST CANADIAN OR NORTH AMERICAN CONDITIONS.

IN PARTICULAR, BOTH THE INDUSTRY AND ITS REGULATORS NOW REALISE THAT GAS PRICES ARE DRIVEN BY COMPETITION WITH OTHER ENERGY FORMS AND WITH ALTERNATE SUPPLIES OF GAS. AND SINCE CRUDE OIL WILL BE THE TREND SETTER FOR ENERGY PRICES FOR YEARS TO COME, WE MUST CAREFULLY POSITION OURSELVES TO COMPETE AGAINST ITS INFLUENCE.

IN THE CONTEXT OF THIS CONFERENCE, GAS AND OIL ISSUES ARE LINKED AND CAN BE EXAMINED TOGETHER. I HOPE MY REMARKS ON OUR PROGRESS TOWARDS GAS DEREGULATION ARE HELPFUL IN THE BROADER SPHERE OF OUR CANADIAN GAS BUSINESS IN A NORTH AMERICAN MARKET.

IN THE MONTHS AHEAD I BELIEVE INDUSTRY AND GOVERNMENT SHOULD CONTINUE TO WORK HARD TO MAKE DEREGULATION WORK, RATHER THAN OPT FOR THE STATUS QUO OR

REREGULATION. WE SHOULD -- AND WE MUST -- GET RID OF THE UNNECESSARY REGULATORY CRUTCHES SO THAT WE CAN ADJUST, ADAPT, COMPETE AND THEREBY ENJOY GROWTH IN THE NATURAL GAS INDUSTRY.

THANK YOU.

REMARKS BY
STEPHEN T. BELLRINGER
PRESIDENT
UNION GAS LIMITED

TO

THE INTERNATIONAL OIL AND GAS MARKETS
CONFERENCE

TUESDAY, SEPTEMBER 16, 1986
CALGARY, ALBERTA

THE IMPACT OF CANADIAN GAS DEREGULATION:

A DISTRIBUTOR'S VIEW

GOOD MORNING LADIES AND GENTLEMEN. MAY I FIRST TELL YOU HOW MUCH I APPRECIATE BEING INVITED HERE TO PRESENT AN ONTARIO NATURAL GAS DISTRIBUTOR'S VIEW OF THE DEREGULATED MARKETPLACE.

BECAUSE MANY OF YOU HERE TODAY ARE VISITORS TO CANADA AND, AS SUCH, WOULD NOT NORMALLY BE FAMILIAR WITH THE CANADIAN GAS BUSINESS IN GENERAL, OR UNION GAS LTD. IN PARTICULAR, I WOULD LIKE TO TAKE A FEW MINUTES TO DESCRIBE OUR COMPANY AND THE DISTRIBUTION ACTIVITIES WITHIN THE PROVINCE OF ONTARIO.

NATURAL GAS HAS BEEN PRODUCED AND SOLD IN SOUTHERN ONTARIO SINCE THE LATE 1800'S. IN FACT, DURING THE 1890'S, NATURAL GAS WAS EXPORTED FROM OUR AREA INTO THE UNITED STATES, THROUGH WOODEN PIPES, AS FAR SOUTH AS TOLEDO, OHIO. UNION GAS LTD., THE COMPANY WHICH I REPRESENT, WAS ESTABLISHED 75 YEARS AGO AND IS BASED IN CHATHAM, ONTARIO, ABOUT 45 MILES EAST OF DETROIT, MICHIGAN. AS THE SECOND LARGEST INTEGRATED GAS UTILITY IN CANADA, OUR BUSINESS CONSISTS OF TWO MAIN SEGMENTS: STORAGE
IDE # 1 AND TRANSPORTATION, AND DISTRIBUTION. THESE TWO AREAS ARE ABOUT EQUAL IN SIGNIFICANCE TO OUR OVERALL OPERATION.

AS A GAS STORAGE AND TRANSMISSION BUSINESS, WE OPERATE THE LARGEST STORAGE FACILITIES IN CANADA. THESE FACILITIES, LOCATED IN FORMER GAS-PRODUCING RESERVOIRS NORTH OF CHATHAM, HAVE A WORKING CAPACITY OF ABOUT 100 BCF. THE TOTAL ANNUAL VOLUME WE TRANSPORT FOR OTHER EASTERN CANADIAN UTILITIES IS ABOUT 192 BCF.

AS A DISTRIBUTION BUSINESS, UNION GAS SERVES SOME 515,000 RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS THROUGHOUT SOUTHERN ONTARIO, FROM WINDSOR IN THE WEST TO OAKVILLE JUST OUTSIDE TORONTO IN THE EAST. OF OUR TOTAL MARKET VOLUME OF 270 BCF, 60 PERCENT GOES TO MAJOR INDUSTRIAL CUSTOMERS.

UNION GAS LTD. IS A WHOLLY OWNED SUBSIDIARY OF UNION ENTERPRISES, WHICH IS ALSO THE PRINCIPAL SHAREHOLDER OF PRECAMBRIAN SHIELD RESOURCES OF CALGARY, NUMAC OIL OF EDMONTON, AND PSR GAS VENTURES, A GAS BROKERAGE AND MARKETING ORGANIZATION WHICH IS BASED HERE IN CALGARY. EACH OF THESE COMPANIES OPERATE INDEPENDENTLY.

#2 THE OTHER MAJOR GAS DISTRIBUTORS IN ONTARIO ARE CONSUMERS GAS OF TORONTO AND ICG (ONTARIO) (FORMERLY NORTHERN AND CENTRAL GAS). (SEE MAP)

NOW THAT I HAVE INTRODUCED OUR BUSINESS, I WOULD LIKE TO OUTLINE THE ISSUES THAT WERE BEFORE THE GAS INDUSTRY IN 1985. THIS WILL HELP TO PUT TODAY'S ISSUES IN THE PROPER CONTEXT.

IN 1985 THERE WAS A SENSE WITHIN THE GAS INDUSTRY IN CANADA THAT WE SHOULD BE MOVING TOWARD MORE "MARKET SENSITIVE PRICING", INVOLVING GREATER USE OF COMMERCIAL NEGOTIATION RATHER THAN GOVERNMENT ADMINISTRATION.

DURING LENGTHY DISCUSSIONS LAST YEAR, A NUMBER OF POINTS WERE AGREED UPON, IN PRINCIPLE, BETWEEN THE PRODUCTION, TRANSMISSION AND DISTRIBUTION SECTORS OF THE INDUSTRY, AS TO WHAT HAD TO BE DONE TO ACCOMPLISH THIS RESULT. THERE WAS NO REALISTIC EXPECTATION OF DEREGULATING THE INDUSTRY.

HOWEVER, TWO SIGNIFICANT ITEMS WERE LEFT UNRESOLVED, WHICH IN SOME PEOPLE'S MINDS WERE BASICALLY TRADE-OFFS. THE PRODUCERS FELT THAT THEY REQUIRED GREATER ACCESS TO THE MARKETS, DOMESTIC AND EXPORT; AND THE DISTRIBUTORS FELT THEY REQUIRED GREATER ACCESS TO SUPPLY. DURING INDUSTRY DISCUSSIONS, THESE TWO MATTERS COULD NOT BE RESOLVED. THESE DISCUSSIONS WERE FOLLOWED BY THE OCTOBER 31ST FEDERAL-PRODUCING PROVINCE AGREEMENT ON NATURAL GAS MARKETS AND PRICES. THIS WAS AN AGREEMENT TO PROVIDE FOR MARKET SENSITIVE PRICE BUT NOT TOTAL DEREGULATION OF THE INDUSTRY.

ONE ASPECT OF THE AGREEMENT, AMONG OTHER THINGS, WAS TO PROVIDE FOR A REVIEW OF SURPLUS TESTS FOR EXPORT MARKET ACCESS. I QUOTE DIRECTLY FROM THE AGREEMENT, "THE GOVERNMENTS ANTICIPATE THAT REVIEWS OF SURPLUS TESTS UNDERWAY OR SHORTLY TO BE INITIATED BY THE NATIONAL ENERGY BOARD AND BY THE APPROPRIATE PROVINCIAL AUTHORITIES WILL RESULT IN SIGNIFICANTLY FREER ACCESS TO DOMESTIC AND EXPORT MARKETS AND THUS WILL CONTRIBUTE TO THE ACHIEVEMENT OF THE MARKET-ORIENTED PRICING SYSTEM CONTEMPLATED IN THIS AGREEMENT." PLEASE NOTE THE REFERENCE TO FREER ACCESS AND NOT TOTAL DELETION OF THE TEST.

REFERENCE TO THE EQUALLY IMPORTANT ISSUE OF THE DISTRIBUTOR'S ACCESS TO SUPPLY WAS ALSO CONTAINED IN THE FOLLOWING QUOTE REGARDING THE COMMERCIAL RENEGOTIATION OF VOLUMES: "PRIOR TO NOVEMBER 1, 1986 NEGOTIATIONS SHALL COMMENCE BETWEEN DISTRIBUTORS, SHIPPERS AND THE PRODUCERS SUPPLYING THE GAS IN QUESTION, RESPECTING THE PRICE TO BE PAID FOR NATURAL GAS DELIVERED UNDER EXISTING CONTRACTS. PRICES RESULTING FROM SUCH NEGOTIATIONS SHALL COME INTO EFFECT NOVEMBER 1, 1986 AND AS AGREED THEREAFTER. WHERE CONTRACT RENEGOTIATIONS BETWEEN BUYERS AND SELLERS, WHETHER OF PRICE OR VOLUME, TAKES PLACE IN GOOD FAITH AND ON A VOLUNTARY BASIS, GOVERNMENTS WILL NOT OBSTRUCT THE RESULTING COMMERCIAL TRANSACTIONS."

WHERE ARE WE TODAY ON THESE TWO IMPORTANT ISSUES, ACCESS TO MARKETS AND ACCESS TO SUPPLY?

WITH REGARD TO DOMESTIC MARKETS, T-SERVICE HAS BEEN PUT IN PLACE IN THE EAST, AND PRODUCERS ARE MAKING DIRECT SALES TO FORMER UTILITY AND SYSTEM GAS CUSTOMERS. THE IMPROVEMENT IN ACCESS TO DOMESTIC MARKETS HAS BEEN SIGNIFICANT.

WITH REGARD TO THE MATTER OF EXPORTS, THE NATIONAL ENERGY BOARD HEARING ON SURPLUS TESTS HAS BEEN HELD AND THE NUMBER OF YEARS REQUIRED IN RESERVE HAS BEEN REDUCED FROM 25 TO 15. THERE IS SOME DEBATE AS TO THE EXACT EFFECT OF THE CHANGE FROM A 25 YEAR VERSUS A 15 YEAR SURPLUS DEPENDING ON YOUR VIEW OF PROJECTIONS OF INCREASED MARKETS AND THE SUBSEQUENT NEED FOR INCREASED RESERVES. THE PROVINCIAL REVIEW HERE IN ALBERTA IS YET TO TAKE PLACE. SO THERE HAS BEEN SOME IMPROVEMENT WITH RESPECT TO ACCESS TO EXPORT MARKETS ... ALTHOUGH WE UNDERSTAND THERE ARE SOME WHO FEEL THE DEGREE OF IMPROVEMENT HAS NOT BEEN ENOUGH.

ON THE PARALLEL SIDE, ALL DISTRIBUTORS HAVE ASKED FOR VOLUME RENEGOTIATION OF THEIR LONG-TERM CONTRACTS WITH THEIR MAIN PIPELINE SUPPLIERS IN ORDER TO GAIN GREATER ACCESS TO SUPPLY. THIS WOULD HELP TO ENSURE MARKET PRICES FOR THE MAJORITY OF NATURAL GAS CUSTOMERS.

INTENSE TALKS HAVE TAKEN PLACE WITH RESPECT TO VOLUME AND PRICE, BUT AS YET, NO MOVEMENT HAS BEEN MADE ON THE VOLUME POINT. THUS, WHILE THERE HAS BEEN SOME RELAXATION OF THE EXPORT TEST (PARTICULARLY SHORT TERM), AND GREATER DOMESTIC ACCESS TO MARKETS, THERE HAS BEEN NO CHANGE WHATSOEVER IN THE QUID PRO QUO ACCESS TO SUPPLY BETWEEN DISTRIBUTORS AND SUPPLIERS.

THE PRICE ISSUE IS CURRENTLY BEFORE THE PRODUCING INDUSTRY IN THE FORM OF RENEGOTIATED DISTRIBUTION CONTRACTS SO I WILL NOT COMMENT IN DETAIL; BUT I BELIEVE THE PROPOSALS ARE A REALISTIC REFLECTION OF THE CURRENT ECONOMIC AND POLITICAL REALITY. WHEN ONE CONSIDERS THE CURRENT COST OF CMP'S AND INCENTIVE GAS PLANS, COMBINED WITH THE BENEFIT OF THE REMOVAL OF PGRT, THE INCREMENTAL COST TO THE IMPORTANT PRODUCING SEGMENT OF THE INDUSTRY IS FAIR IN FINANCIAL TERMS. HOWEVER, THE ACCEPTANCE OF THE PROPOSED DISTRIBUTORS' PRICING AGREEMENT IS VERY IMPORTANT IN ESTABLISHING A COMMERCIAL ATMOSPHERE FOR DOMESTIC NATURAL GAS PRICING.

SUBSEQUENT TO THE OCTOBER 31ST AGREEMENT, DESPITE NO ASSURANCES OF GREATER SUPPLY FLEXIBILITY, THE PROVINCE OF ONTARIO DID PROVIDE FOR GREATER ACCESS TO ITS MARKETS. ONTARIO'S ENERGY MINISTER, THE HON. VINCENT KERRIO, SUPPORTED THE AGREEMENT IN HIS STATEMENT OF DECEMBER 3, AND INDICATED THAT "ONTARIO SUPPORTS THE INTRODUCTION OF INTERIM CONTRACT CARRIAGE (OR T-SERVICE AS WE CALL IT) FOR THE TRANSITIONAL PERIOD ENDING OCTOBER 31, 1986." THE ONTARIO ENERGY BOARD QUICKLY FOLLOWED THIS POLICY GUIDELINE AND HAD INTERIM T-SERVICE RATES IN PLACE PRIOR TO CHRISTMAS 1985. TO DATE, BOTH THE ONTARIO ENERGY BOARD AND THE NATIONAL ENERGY BOARD HAVE RESPONDED QUICKLY WITH PRACTICAL DECISIONS ON VERY DIFFICULT ISSUES.

SLIDE # 3 NEVERTHELESS, THE GREATEST IMPACT ON THE ENERGY MARKET AND MARKET SENSITIVE PRICING IN THE PAST YEAR HAS BEEN THE PLUMMETING CRUDE OIL PRICES THROUGHOUT THE WORLD. (SEE SLIDE). IT WOULD BE INTERESTING INDEED TO CONTEMPLATE THE RESULTS, IF, SUBSEQUENT TO OCTOBER 31ST, CRUDE OIL PRICES HAD RISEN RATHER THAN FALLEN. IT IS OBVIOUS THAT LOWER CRUDE PRICES RATHER THAN THE OCTOBER 31ST AGREEMENT IS CREATING THE CURRENT FINANCIAL HARDSHIP ON THE PRODUCING SEGMENT.

LOOKING AT THE MARKET, THESE LOWER CRUDE PRICES HAVE DROPPED #6 FUEL OIL IN CERTAIN SEGMENTS OF OUR MARKET, DOWN AS LOW AS $2.75 A MILLION BTU'S. AT THE SAME TIME, WE WERE SELLING GAS AT VERY LOW MARGINS, 6 TO 8 PERCENT OF SELLING PRICES AT $4.25 A MILLION BTU'S, KEEPING IN MIND THAT OUR OWN GAS SUPPLY HAS NOT BECOME MARKET SENSITIVE. THIS SET OF CIRCUMSTANCES PROMPTED THREE ACTIVITIES THAT HAVE BEEN TAKING PLACE SINCE THE AGREEMENT WAS SIGNED.

1. A LARGE NUMBER OF CUSTOMERS HAVE DECIDED TO STAY ON SYSTEM GAS AND HAVE ARRANGED COMPETITIVE MARKETING PROGRAMS TO OBTAIN TRADITIONAL SERVICE FOR THEIR PLANTS, AT A DISCOUNT. IN EASTERN CANADA, SOME 250 BCF OF GAS NOW MOVES UNDER SOME FORM OF COMPETITIVE MARKETING PROGRAM.

2. GAS PRICES FOR THE LARGER INDUSTRIAL AND COMMERCIAL MARKET, AFFECTING SOME 450 CUSTOMERS IN ONTARIO, WERE DUE TO CLIMB ON MAY 1ST, 1986 BY 35 CENTS A GIGAJOULE (37 CENTS PER MCF). BUT AT THE SAME TIME, COMPETING FUELS WERE DROPPING BY THE EQUIVALENT OF A DOLLAR AND A HALF. AT THIS TIME, THE ONTARIO DISTRIBUTORS AND TCPL DEVELOPED "WGMIP" -- TO REPLACE INCENTIVE GAS -- AND HELD ON TO OVER 95 PERCENT OF THIS MARKET, WHICH UNDOUBTEDLY WOULD HAVE MOVED TO HEAVY FUEL OIL. UNION ESTIMATES THIS PREVENTED SOME 100 OF OUR CUSTOMERS (USING 15-20 BCF) FROM SWITCHING TO ALTERNATIVE FUELS.

3. PENDING THE RENEGOTIATION OF OUR LONG-TERM CONTRACTS, A NUMBER OF BROKERS AND INDEPENDENT PRODUCERS BEGAN WORKING WITH INDUSTRIAL CUSTOMERS WHO MIGHT WISH TO SECURE THEIR OWN NATURAL GAS SUPPLIES. AND A NUMBER OF DIRECT SALES HAVE BEEN MADE TO THESE CUSTOMERS -- BOTH THE BUY-SELL TYPE AND THE T-SERVICE TYPE. ONCE THE CUSTOMER DECIDES TO GO DIRECT PURCHASE, DISTRIBUTORS WORK WITH THEM TO ASSIST AND KEEP THEM OUT OF TROUBLE. DISTRIBUTORS, IN GENERAL, WOULD PREFER TO KEEP THEIR CUSTOMERS ON SYSTEM GAS; BUT IF NOT ON SYSTEM GAS, ON GAS.

CURRENTLY, IN THE UNION SYSTEM, ABOUT 85 PERCENT OF ALL OUR INDUSTRIAL VOLUMES ARE MOVING UNDER SOME FORM OF INCENTIVE GAS, CMP OR DIRECT PURCHASE MECHANISM. BUT THIS REPRESENTS LESS THAN 1/10 OF 1 PERCENT OF THE NUMBER OF CUSTOMERS. AS YET THE REMAINDER HAVE RECEIVED NO BENEFIT FROM THE OCTOBER 31ST AGREEMENT.

NEXT I WOULD LIKE TO TURN TO SOME OF THE MYTHS ABOUT DISTRIBUTOR'S RETURNS.

THE FIRST MYTH THAT PLAGUES THE DISTRIBUTORS IS THAT WE OPERATE IN A RISK-FREE ENVIRONMENT. AN EXAMPLE TO THE CONTRARY -- UNION GAS WROTE OFF $12 MILLION DOLLARS RELATING TO PREPAID GAS COSTS LAST YEAR. UNCONTROLLABLE FACTORS SUCH AS CHANGES IN SALES VOLUMES, OPERATING COSTS, SUDDEN CHANGES IN CLIMATE (FOR EXAMPLE THE WARM WINTER OF 1982-83), AND UNPREDICTED ECONOMIC DOWNTURNS, ARE EVER-PRESENT ELEMENTS OF RISK IN OUR BUSINESS. AND BECAUSE WE ARE A REGULATED INDUSTRY, WE CAN'T COVER OUR LOSSES BY PASSING ON THE COSTS OF A BAD YEAR TO THE CUSTOMER. MY COMPANY IS AT THE RISK OF MARKET UNTIL AT LEAST APRIL 1988.

THEN THERE IS THE MYTH THAT SAYS BEING REGULATED IS A DISINCENTIVE TO IMPROVING EFFICIENCY. ON THE CONTRARY, OTHER THAN GAS SUPPLY COSTS, UNION HAS GONE FIVE YEARS WITHOUT A RATE INCREASE, DURING A PERIOD OF ESCALATING INFLATION. MOREOVER, DURING THIS PERIOD WE HAVE ADDED 50,000 NEW CUSTOMERS, INCREASED OUR VOLUMES AND SIGNIFICANTLY EXPANDED OUR STORAGE AND TRANSPORTATION FACILITIES. WE HAVE ACHIEVED THIS BY CUTTING OPERATING COSTS AND INCREASING PRODUCTIVITY. IN 1983-84 WE REDUCED OUR WORKFORCE BY NEARLY 10 PERCENT THROUGH EARLY RETIREMENT AND STAFF CONTROL PROGRAMS.

AND AS TO THE MYTH THAT BECAUSE WE ARE REGULATED WE HAVE NO INCENTIVE TO SELL OUR GAS COMPETITIVELY, I HAVE ALREADY REFERRED TO THE FACT THAT 85 PERCENT OF OUR INDUSTRIAL VOLUMES ARE MOVING UNDER NON-TRADITIONAL COMPETITIVE PROGRAMS.

TURNING NOW TO THE 1987 AGENDA, FROM A DISTRIBUTOR'S POINT OF VIEW, IT SEEMS TO ME THAT THE QUESTION OF INCREASED DISTRIBUTOR ACCESS TO GAS SUPPLIES ON BEHALF OF GAS CONSUMERS AT LARGE, HAS TO BE ONE OF THE PRIMARY ISSUES FOR 1987.

I HAVE PREVIOUSLY REFERRED TO THE OBSTACLE TO MARKET RESPONSIVE PRICING IN THE FORM OF THE DISTRIBUTOR'S LONG TERM CONTRACTS WITH SUPPLIERS AT NON-MARKET PRICES. OUR CONTRACTS ARE STAGGERED FOR EXPIRATION BETWEEN THE EARLY AND MID 1990's. LAST YEAR WE ATTEMPTED TO RENEGOTIATE SOME OF THE VOLUMES ON THE BASIS OF PAYING THE DEFERRED CARRYING COSTS ON VOLUMES TO BE USED IN THE FUTURE. THIS WAS TURNED DOWN IN INDUSTRY DISCUSSIONS MORE THAN A YEAR AGO. SUBSEQUENT TO THE RECOGNITION OF THE ACCESS TO SUPPLY ISSUE IN THE OCTOBER 31 AGREEMENT, WE TRIED TO COMMERCIALLY RENEGOTIATE VOLUMES WITHOUT SUCCESS.

THEREFORE, IN TERMS OF OUR POSITION ON EXPORT SUPPLIES, IT SEEMS TO ME THAT THE DOMESTIC TOPGAS AND DISTRIBUTOR'S SUPPLY ACCESS ISSUES MUST BE ADDRESSED BEFORE WE TACKLE, FOR THE SECOND TIME, ANY ADDITIONAL EXPORT SURPLUS ISSUES.

SECONDLY, WE MUST ENSURE THAT THE CUSTOMERS WHO, BECAUSE OF LACK OF SIZE AND FINANCIAL CLOUT CANNOT NEGOTIATE COMPETITIVE MARKET-PRICE DEALS, WILL HAVE ACCESS TO THE BENEFITS OF MARKET SENSITIVE PRICING.

THIRDLY WE ARE SERIOUSLY CONCERNED ABOUT THE HEALTH OF THE PRODUCTION INDUSTRY IN CANADA. UNDOUBTEDLY THE SOURCE OF THE DIFFICULTY IS LOW CRUDE PRICES. WE WANT A HEALTHY AND VIGOROUS GAS EXPLORATION AND PRODUCTION INDUSTRY AND BELIEVE THAT IN OUR PRICE NEGOTIATIONS WE HAVE TAKEN A REALISTIC POSITION. WE WELCOME THE RECENT FEDERAL GOVERNMENT MOVES TO ASSIST THE INDUSTRY ... AND WE CAN ASSURE YOU THAT WE WILL CONTINUE TO WORK HARD TO MAINTAIN AND INCREASE SECURE EASTERN CANADIAN MARKETS FOR WESTERN CANADIAN NATURAL GAS.

IN CLOSING, IF 1985-86 WAS A "TRANSITION" PERIOD, THEN NEXT YEAR'S AGENDA CAN BE CALLED A PERIOD OF "FINE" TUNING. WE WILL BE LEARNING TO LIVE WITH A NEW SET OF PARAMETERS FOR THE NATURAL GAS INDUSTRY IN CANADA.

PROSPECTS FOR HEAVY CRUDE OIL DEVELOPMENT

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Introduction

The recent drop in oil prices has complicated the preparation of an oil report. The actual price level is significant but the amount of publicity attendant thereto also has a profound effect. In 1985, three knowledgeable people commented on future price possibilities. Two (Desprairies, 1985; Goldstein, 1985) estimated that a drastic drop would be to the $20-25 per barrel range, whereas Singer (1985), basing his estimate upon production capacities of the various producers, foresaw in January, 1985, the possibility of oil prices falling as low as $10 per barrel. The effect of the price changes on heavy crude oil and natural bitumen is severe in most parts of the world, mainly because these commodities are chemically very like refining residua.

There are a number of problems with heavy crude oil and natural bitumen which center on their high viscosity, a rough gauge of which is the density (usually expressed as degrees gravity API or as kg per cubic meter). This characteristic makes heavy crude oil and natural bitumen difficult to produce and store on the lease, transport, and refine, and each adds to cost. The most severe difficulty related to heavy crude oil and natural bitumen, however, is the loss of the high productive capacity that can be achieved with conventional crude oil, whether flowing or even pumping.

Definitions

The United Nations Information Centre for Heavy Crude and Tar Sands has adopted definitions which are followed herein, although it is recognized that hydrocarbons are, in effect, a continuum from the kerogen of oil shale through the natural bitumens to crude oil, natural gas and condensate. Natural bitumen is any natural hydrocarbon more viscous than 10,000 cp (mPa.s). Crude oil is less than 10,000 cp. Extra-heavy crude oil is less than 10° API, whereas heavy crude oil is 10° API or greater and 20° API or less. The bitumen at Athabasca is an example of natural bitumen, the oil in the Orinoco Oil Belt of Venezuela is mostly extra-heavy crude oil, and much of the oil of the Los Angeles Basin and the San Joaquin Valley is heavy crude oil. Natural bitumen is also called native bitumen and natural asphalt; the rocks containing heavy crude oil are known as tar sands and oil sands, although they are often carbonate rocks. In purely practical terms, any oil capable of being produced from a well is considered to be a heavy oil and not a bitumen; that is, a crude oil of less than 10° API is extra-heavy oil, regardless of the viscosity.

Another definition of heavy oil, used by the National Petroleum Council, is any oil that will yield 15% residual oil at a temperature of 1010°F (Oil & Gas Journal, 1983). This greatly expands the data base of heavy crude oil to include many oils otherwise considered to be conventional (Table 1). The disadvantage of this definition is that relatively few crude oils include the requisite analyses. Table 1 obviously includes very few conventional crude oils, those of less than 20° API. Most of the analyses are from Aalund (1983a-n). Where possible, the viscosities are converted to centistokes (cst) at about 110°F. The oils generally are on a gas-free basis. Many more analyses are available but Table 1 is sufficiently complete to show that the heavy oils and natural bitumens over time have undergone a natural distillation comparable to refinery distillation and that the residua of light oils are similar to whole heavy oils and natural bitumens. The residua in Table 1 are given the same numbers as the oils to which they refer. The three conventional crudes all have yields of less than 15% at high cut points whereas the heavy conventional crudes yield more than 15% residua at high cuts. The API gravities of heavy conventional crudes are comparable to those of the heavy crudes in the distillation residua but the yields of the latter are decidedly greater, as is the content of vanadium and nickel. Unfortunately, too few analyses of heavy crude oils are available for more definitive conclusions. The natural bitumens are far more closely allied to the varius residua than to any of the whole crude oils.

Resources

The total amount of heavy crude oil and natural bitumen in the world is large, perhaps as great as 7.0 trillion (10^{12}) barrels although the recoverable portion of this would be much smaller, possibly some 0.9 trillion barrels. But as long as a very large excess producing capacity of conventional crude oil exists in the world, not much heavy crude oil and natural bitumen will enter world markets. This is especially so at a time of worldwide excess refining capacity, when most of the capacity more technologically advanced than atmospheric distillation is located in North America. Of the natural bitumen in place, 2.6 trillion barrels or 75% is located in Canada, more precisely, in Alberta, in the Athabasca, Cold Lake, and Peace River Sandstone deposits and in the Carbonate Trend. Nearly 43 billion (10^9) barrels or only 1.2% is found in the United States, scattered in numerous deposits, the most attractive of which are the in the state of Utah. Giant bitumen deposits (at least on billion barrels each) contain 99% of the natural bitumen; there are 22 of these. Those of Canada and the USSR (22%) are the largest known in the world. Fifty-six other countries contain evidence of natural bitumen.

The geographic distribution of the in-place reserves of extra-heavy crude oil and heavy crude oil is surprising because, of the total of nearly 2.1 trillion barrels, about two-thirds is located in Venezuela, including the Orinoco Oil Belt with more than half of the world's total reserves. The United States and Canada are not well endowed. The United States has over 90 billion barrels, and Canada has 11.3 billion barrels of in-place reserves. The United States has produced about 10.1 billion barrels with as much as another 18 billion barrels of recoverable reserves. Canada has produced 438 million barrels, with another 749 million barrels of recoverable reserve.

Like conventional oil, the bulk of heavy crude oil reserves is contained in a relatively few giant fields, those fields with an ultimate recovery (cumulative production plus recoverable reserves) of 500 million barrels. The 57 giant fields containing heavy crude oil and extra heavy crude oil, excluding the Orinoco Oil Belt, contain 183 billion barrels. Thus, 18% of giant fields produce heavy crude oil.

The amount of undiscovered heavy crude oil in the world—about 637 billion barrels—is large, but most of it is outside the United States and Canada. The United States has about 9% and Canada about 3% of this total, for a total of about 28.5 billion barrels recoverable. Although recoverability is highly subjective, depending among other things on price, cost, and technology, an order of magnitude may be inferred.

For the near and intermediate terms, say to the year 2000, the heavy crude oil and natural bitumen resource bases will not inhibit their development. These resources are very site-specific, however, and require a conjunction of favorable circumstances to be producible under existing mid-1986 economic conditions. Such conditions are generally applicable for a variety of reasons in Canada and in the United States, including the regulatory environment, reserves, new discoveries, and, importantly, the availability of proper refining facilities.

The oil fields in Dwight's Petroleum Data System (PDS) for the United States contain a total of 18.81 billion barrels of heavy crude oil, both on- and offshore. This is an approximation because every field in the file does not have a density value and not all states record data by individual reservoir. These data give, however, an idea of heavy crude oil relations between onshore location, depth, and gravity. The United States has very little oil in production heavier than 10° API. About 3.5 billion barrels, or nearly 19%, is offshore. Of this, 11% is from 10-15° API and more than 80% is 16-20° API. Water depths are not recorded. Of the reservoirs, 10% are at 500 ft or less, 72% are between 2001 and 5000 ft, and 18% are below 5000 ft. About 75% of the onshore fields are in the state of California, 9.7% are below 10° API, 31% are between 10° and 15° API, and 59% lie between 16° and 20° API. Only 5.4% are above 500 ft, 52.7% lie between 501 and 2000 ft, 37.4 between 2001 and 5000 ft, and 4.5% below 5001 ft. Thus, 4.8 billion barrels or 25.5% of the oil is 16-20° API at depths of 501-2000 ft, 3.2 billion barrels is 16-20° API from 2001-5000 ft, 3.2 billion barrels is 10-15° API from 501-2000 ft, ~~and~~ 1.1 billion barrels is below 10° API from 2001-5000 ft, and 1.3 billion barrels is 10-15° API from 2001-5000 ft. Only small amounts of the heavy crude oil are found above 500 ft or below 5000 ft. Offshore, 60% of the heavy crude oil is 16-20° API at depths of 2001-5000 ft.

Geochemistry

The evolution of organic matter from its deposition in sediments to the gasoline in cars is fascinating. Each step is equally important to the final product and influences both cost and price. The present discussion is based upon the assumption that most, if not all, petroleum originates from organic matter growing on the earth's surface or in the earth's waters and accumulating, with sediments, generally near shore in the ocean, deltaic environments being especially favorable.

The organic matter first undergoes diagenetic change within the sediment and is slowly buried with it. The sediment, whether clastic or carbonate, consolidates, and the gradual rise in temperature due to depth of burial alters the organic matter. The first stage is the development of kerogen, such as is found in oil shale. With continuing rise of temperature, usually the result of deeper burial, part of the kerogen is upgraded to immature petroleum. At this stage it is very viscous and contains most of the undesirable metals and other non-hydrocarbons which make refining difficult. Sometimes this immature oil is expressed directly into traps and recovered, as with the Monterey diatomites in the Santa Maria Basin. More often, probably 95% of the time, the immature oil is retained in the sediment until it is expressed as oil, after exposure to still higher temperatures. The maturation process certainly requires heat, although it may be aided by catalysts as yet not positively identified in the sediment. The expressed oil migrates a greater or lesser distance, normally under the influence of a hydrodynamic system, until it is trapped through bouyancy against an impermeable bed, thus creating an oil pool. With increasing temperatures, normally through greater burial, natural gas is the product of the evolutionary process. With sufficiently high temperature the organic matter will eventually form coke and graphite. The natural maturation process is thus very similar to refining: distillation and cracking, perhaps catalytic catcracking.

In the process of maturation of petroleum, two imponderables are time and catalysis. Presumably, each plays an important role, but the extent is exceedingly difficult to quantify. Two aspects of the process can be quantified and are interrelated: depth and temperature. Depth can be measured, as can temperature albeit often with less accuracy. Figure 1 shows the interplay between depth, temperature gradient, and one of the imponderables, time; the band labeled crude oil is usually called the "oil window," for at the top of the band generation commences, and at its bottom, oil is converted to wet gas and then to dry gas. This is a reflection of hydrocarbon evolution from kerogen to bitumen to oil to gas and elemental carbon. Nature is acting in the same manner as a refiner, but less efficiently, with increasing temperature leading to lighter hydrocarbons at the expense of heavier ones. Finally, through a deficiency in available hydrogen, a great deal of carbon is left.

But even this is not the end of the story. Heavy crude oil and natural bitumen may result from expulsion of immature oil from the sediments; this accounts for no more than 5% of such viscous oils. Most of the heavy crude oil and natural bitumen result from the destruction of conventional oil deposits through biodegradation, water washing, and evaporation. All these processes act first on the paraffins, the most volatile and molecularly simplest of the hydrocarbon mixture comprising oil deposits, and then on the aromatics and sulfur compounds. As a result, the least desirable elements and components are concentrated in the remaining portions of the oil and, in the case of the natural bitumen, in the residue, again analogous to refining. The undesirables include the large hydrocarbon molecules (the resins and asphaltenes), the heteroatoms (with sulphur, vanadium, nickel and other metals), the many trace metals, and oxygen and nitrogen. This residue may be very viscous, forming natural asphalt when mixed with mineral matter or accumulates as pitch lakes if quite free of such extraneous material. Important effects of crude oil degradation or alteration are given in Table 2.

Distillation in a refinery may be predetermined, with ever-heavier components boiled off, in part under vacuum. In nature the process is more inferential, with relative temperatures indicated by degrees of coloration on certain fossils or by stages of coalification, most prominently the vitrinites. Cracking is common to both refining and nature.

Costs

Data required to determine costs of finding natural bitumen are roughly the same as for most other mineral commodities, mainly involving surface geology, geophysics and core drilling. The use of the latter has been described by Ako et al. (1983) for the large Nigerian tar-sand deposits. A methodology for an examination of the large United States deposits, involving surface geology, well logs, and cores is detailed by the Interstate Oil Compact Commission (1985) and is also given in Meyer and Schenk (in press). None of these explicitly define costs. The Canadian oil sands deposits have been known for a very long time and, like oil shale in the United States, their hydrocarbon potential has long been recognized. Although only the Canadian material has advanced to the commercial stage, actual cost information is generally proprietary, for only two companies, Sun and Imperial, are directly involved. However, the chairman of Suncor (Oilweek, 1986) has placed the cost of a barrel of oil at full production of 50,000 b/d at about Cdn$20 (US $14.25) per barrel, whereas at production of 39,500 b/d, the cost per barrel rises to Cdn$25 (US $17.85). Suncor estimated the cost of mothballing the plant at Cdn$30-40 million plus high start-up costs. Judging from actions in Canada and considering the time and enormous capital investments made, most probably surface mining operations for natural bitumen will continue unless there are further severe declines in the price of oil. It should be noted that the finding cost does not include the capital investment, so that in mid-1986 dollars a price of at least Cdn$35 would be required to provide a rate of return approximating 15%.

At Cold Lake some natural bitumen is now being produced in situ from the subsurface by enhanced oil recovery methods. This material may be considered to be heavy crude oil from a production standpoint and as such may be considered later.

Lifting costs for heavy crude oil are as difficult to obtain as is true of conventional oil, especially if the term is interpreted broadly to include finding, development, production, and enhanced oil recovery expenses. In addition, heavy crude oil entails added expenses in the field or later for transportation and refining. In many countries in which concessions have been terminated the finding costs, which may or may not have been high, return essentially to zero, leaving the other lifting costs, some of which also were for wells already in place. Production costs in the Orinoco Oil Belt have been stated to be about $2.00 at the well head (Platts Oilgram, 1986). Assuming the entire Belt encompasses similar production characteristics, this still leaves a multitude of costs to be faced. Costs elsewhere mostly must be surmised, usually from price minima necessary to keep up conventional crude oil production.

Thus, the marginal cost of production in a number of North Sea fields, including the common marker crude Brent Blend, is less than $5.00 per barrel (Oil & Gas Journal, 1986b). Desprairies et al. (1985) show the amounts of the world's reserves and resources of oil which could be produced at different price levels (US $1983) per barrel. In this report, by area but not by oil

API gravity, the authors indicate that $40-50 or more would be needed to exploit the huge resources of the Orinoco Oil Belt, the Canadian oil sands, and oil shales. Kuuskraa (1986) has tabulated replacement costs for domestic United States conventional oil but does not separate heavy crude oil. Leprince (1985) places a maximum technical cost on heavy crude oil of $13-14 per barrel. This is because the oil must be diluted or upgraded in the field and transported at a total additional cost of $7-8. These limiting values are not commonly reached. Since Leprince's report was prepared just before the drop in prices, it demonstrates again the difficulties faced in dealing with heavy crude oil.

A report on the world energy outlook in May, 1986 by the Institute of Energy Economics (1986) does not consider heavy crude oil but gives some limiting prices from which certain maximum costs may be inferred. For example, Mideast crude oil can be delivered to the United States for $3.00 per barrel whereas $17.00 is given as the breakeven price for lower-48 oil and $14.00 for Alaskan crude. These prices would drop to $12.00 for Alaska and $8.00 for the lower-48 on a no-cash-flow basis comparable to the Mideast OPEC. The Institute estimates that $15.00 per barrel would result in the shut-in of 270,000 b/d of stripper production, with 640,000 b/d at $10.00. The Interstate Oil Compact Commission (Oil & Gas Journal, 1986h) reached similar conclusions on the effects of lower prices on the quantities and values of US stripper production, which averages only 2.8 b/d. The effect on national production capacity of each well is not large, but the total effect, according to the Interstate Oil Compact Commission, could measure as much as 239,000 b/d the first year. The net effects on production, reserves, value, and personnel would be felt most keenly in the very mature areas, notably Oklahoma and Kansas. Estimates of the possible repercussions of price drops on US stripper wells are given in Table 3.

Ross (1986) has reviewed the wide range of both finding and production costs in comparing the efficacy of finding and producing reserves as compared with their acquisition by purchase. He concludes that, in the United States, exploration does not justify its expense. No matter how computed (Byrd et al., 1985), finding costs in the United States, at least, have risen steadily over time. Tussing (1986) states a 1985 United States finding cost of $6.40 per barrel. With respect to heavy crude oil, the best that can be said is that much of it is found incidental to the search for conventional crude oil. Much is, in fact, behind the pipe and therefore can be considered to have zero finding cost.

Although some old data are available, the most up-to-date information on the costs of bitumen production in the United States are given in Moore et al., (1984). Of the cited examples (Table 4), only bitumen from the Hondo Field in the offshore of California is presently being produced. Production from the other deposits is too expensive in today's economic climate.

Prices

Information on the prices of crude oil is routinely reported on a weekly basis, but data for heavy crude oil and natural bitumen are seldom reported. It also is difficult knowing the basis for the price quoted, because at least six options are available to the originator of the price. (1) The basic, traditional price is the official, posted price, which may or may not have any relationship to reality, but is the most widely-accepted standard. (2) Spot prices are those paid for small lots, usually through bargaining between buyer and seller. In times of great price and supply instability, spot prices may dominate the oil market. (3) Oil may be treated as a mineral commodity. Futures trading is now practiced on commodity exchanges. For example, the New

York Mercantile Exchange (NYMEX) Futures commit the buyer, often a commodity speculator, to the purchase of a lot of oil, usually 1,000 barrels, at a specified price and time. The commodity market serves to indicate what traders think about the future course of oil prices. (4) The recent weakness in prices resulting from oversupply has brought new life, perfected by Saudi Arabia, to the netback, which results in a price based upon the expected yield of products and thus guarantees a profit to the refiner. There are, no doubt, aspects of netbacks which are not written about, such as discounts. (5) Oil is employed in barter agreements in the counter-trade, in which so many barrels of oil may be traded for so many tons of steel or some other commodity. In this instance, the oil price is implicit, not explicit. (6) Finally, there are the refiner acquisition costs, the amounts paid by refiners above the posted (or other) prices to allow for such losts as transportation from ports.

Table 5, showing a few marker crude oils, clearly depicts the sharp drop in oil prices since last December and price stability before then. This drop has had numerous repercussions, particularly in the developed countries. This time the drop was so rapid that learned papers explaining it were out of date before they could be published. The most notable effect industrially has been the curtailment of exploration and, to only a slightly lesser degree, production. Development can be stopped almost immediately. The number of active rotary rigs is at a post-war low (Table 6). Marginal production, especially offshore and stripper, is either being cut back or shut in as soon as the wells require remedial work. Independent operators and company exploration personnel are drastically reduced, as are refinery workers in those refineries shut down for lack of product demand or inefficiency. Service companies are particular victims of the oil recession although oil field equipment auctioneers are in great demand.

Because heavy crude oil and natural bitumen are higher in cost, each step of the way, than conventional crude oils, their producers are especially hard hit. In March, Texaco shut in 10,000 b/d in the Kern River Field (Crabbe, 1986). On the West Coast, some 5,000 wells producing oil with characteristics similar to that from the Alaskan North Slope (ANS) were shut in by March 31, when ANS oil slipped under $10.00 per barrel. In contrast to most stripper wells, heavy oil wells can usually be placed back into production. Tussing (1986) unambiguously states that crude oil prices of less than $10.00 per barrel make many future drilling projects uneconomic (especially heavy crude oil) but only a fraction of established production capacity has variable operating and maintenance costs greater than $5.00 per barrel. This almost certainly eliminates production by enhanced oil recovery, including most heavy crude oil, which ordinarily is steamed.

Hojabri (1986) suggests that cogeneration can reduce the cost of producing Kern County, California heavy oil by $2.00-5.00 per barrel. Two companies in the area estimate peak demand for gas for this purpose at 600 million ft per day (Oil & Gas Journal, 1986e), a sharp reduction from earlier estimates which would have necessitated a special pipeline (interstate). At this time natural gas is the dominant fuel for California enhanced oil recovery and accounts for 77% of United States cogeneration projects (Oil and Gas Journal, 1986f). In the Kern Front Field, Rintoul (1986) reports a 37% saving in operating cost in a 50-well operation that produces 1600-1700 b/d through cogeneration; in this case, the 43 least-productive wells had been shut in.

In early August, 1986 the ministers of the OPEC countries, in an effort to shore up prices, agreed to reduce production in September and October by about 3.5 million barrels per day. This caused a flurry of activity on the futures market, where West Texas Intermediate for July, 1987, went above $15.00 per barrel. After a few days of consideration on the impossibility of OPEC's goal, prices slipped back. OPEC's reduction in production is nearly impossible because any 13 countries, or even individuals, can rarely agree on anything so drastic. It is thus likely that the spare producing capacity in the world, but mostly in the Persian Gulf, (Table 7) will dominate prices, and consequently, activities for the near term of three to five years. After that time, prices will assuredly rise to levels that can only be highly speculative at this time. Table 8 shows some of the contrasts in prices over the last 6 months (Oil & Gas Journal, 1986).

Recent world oil production, both for the non-Communist countries and the Communist, is given in Table 9. Table 7 shows production for the OPEC countries together with their producing capacities and the production of the members of the Organization of Arab Petroleum Exporting Countries (OAPEC). It is clear that the OPEC countries are producing at only about one-half their maximum sustainable capacity and this is low-cost oil. The OAPEC nations alone have a spare capacity of some 4 million barrels per day. The OAPEC is comprised of Abu Dhabi, Algeria, Bahrain, Egypt, Iraq, Kuwait, Libya, Neutral zone, Qatar, Saudi Arabia, Syria, and Tunisia. Such spare capacities suggest the immense difficulties for the balance of the free world in attempting to maintain more costly production, without price supports of one form or another, in a "free" market.

Recovery

Two entirely different approaches must be taken to the recovery of heavy crude oil and natural bitumen, depending upon the depth below to the ground's surface at which the material lies. Most of the natural bitumen deposits are at or near the surface, with such notable exceptions as the natural bitumen in the Cold Lake deposit. Most of the heavy crude oil deposits are found in the subsurface, and although some are found as deep as 11,000 ft, they mainly are exploited at depths of 5,000 ft or less. There is a complex system of geochemical reasons for this occurrence and other reasons complicate their production, transportation, and refining. This adds up to a considerable expense inhibiting their exploitation in 1986 and in the near future. Exploitation at the present is very site-specific, requiring a conjunction of many favorable influences to create profitability. Unless a country is destitute of petroleum resources, profitability is uppermost in the minds of all nations and companies.

In general, deposits at the surface to a depth of about 300 ft can be mined with power shovels, draglines, and other forms of scrapers. The overburden is then set aside for later reclamation of the site and the oil is physically separated from the rock, usually by a hot water process or by use of a solvent, a procedure unfortunately not as simple as it sounds.

Heavy crude oil and natural bitumen between about 250 or 300 ft and 500 ft is presently largely lost to exploitation because it is too deep to strip-mine and is not deep enough for economical enhanced oil recovery methods to be viable. Experimental methods, mainly electrical, are being investigated to exploit this oil.

Finally, there are the heavy crude oil and natural bitumen deposits below 500 ft or more which are amenable to recovery by known methods, mainly thermal. Outstanding examples are the Cold Lake bitumens in Alberta and the extra-heavy crude oil in the Orinoco Oil Belt.

The economic factors involved in mining natural bitumen (very little heavy crude oil crops out at the surface, most of it having been degraded to natural bitumen) are summed by Early (in press). He makes clear several vital aspects required for the economic recovery of surface and near-surface deposits. Of these the most important are scale of operations, deposit grade, and ore-to-waste (stripping) ratio. Early (in press) concludes that if the deposit is no deeper than 300 ft, the stripping ratio is of the least, and the grade of the deposit of greatest economic importance. Grade or richness must almost always be 8 or 10 wt % or more. Thus, an extraction plant with a capacity of less than 10,000 b/d probably requires very rich, nearby source material.

The recovery of heavy crude oil and natural bitumen in situ from the subsurface most usefully employs assistance by thermal methods. Very little is produced by primary or secondary means. The heat necessary for viscosity reduction may be supplied by in situ combustion but more commonly by steam. The latter frequently consumes one of each three barrels of oil produced, although the cost may be mitigated by using gas first for steam generation and then for the production of electricity through cogeneration, although at the cost of lowering the steam quality.

The Society of Petroleum Engineers publishes quarterly an Enhanced Oil Recovery Field Report, in which typical enhanced oil recovery projects in various fields are detailed from inception to termination. Of these, 20 have dealt with reservoirs containing oil of 20° API or heavier; five of these are still active. Of the five, two — Bellevue and West Heidelberg — are in situ combustion (thermal) and the other three — Midway-Sunset and Mount Poso in California and Tia Juana in Venezuela — are steam drive. The other projects included six steam thermal, four in situ combustion thermal, two polymer, and one each of alternating gas - water, attic air and combination. The thermal methods — steam and in situ combustion — are the only ones that are presently proved to be effective in the enhanced recovery of the heavy oils and, in some instances, the natural bitumens. Steam is especially attractive, although costly in terms of energy consumption (one barrel of each three is used to generate the steam).

Transportation

Conventional oils of low or relatively low viscosity are generally transported by pipeline, with relatively few problems. Because of their high viscosities, heavy crude oil and natural bitumen place much higher requirements and hence costs on their transportation systems, whether truck or pipeline. There are a number of options available, many of which have been summarized for Canada by Urquhart (1986). The options are either to lower the viscosity or else deal with the raw material in some fashion. The problem is that trying to move a heavy crude oil or natural bitumen through a pipeline in its natural state, assuming it will flow at all, imposes a severe hardship on the pumps and limits the distance across which the material can be moved.

With respect to viscosity reduction, there are a number of options. It can be assumed that the heavy crude oil, at the wellhead, has been steamed or perhaps treated with a diluent. Treatment must therefore take into account the water from the steam or the diluent or solvent and its retrieval. Ordinarily, very little associated gas is involved because gas/oil ratios of heavy crude oils are characteristically low.

One approach is to upgrade the produced oil in the field to pipeline quality. This is a high capital alternative for plant construction, since a pipeline is still required to move the oil to a refining center or port.

The heavy crude oil may be diluted with either a natural gas condensate, a light crude oil, or the product from a topping plant. Using condensate is ideal, providing there is enough available and either it need not be recaptured or else there is a return pipeline from the refinery to the site of treatment. Condensate shortage is the biggest problem. The difficulties with a manufactured or topping plant product are those of sufficient supply. Care must be exercised that that product is heavier than the low molecular weight paraffins, such as propane, otherwise the asphaltenes in the heavy crude oil will precipitate. Light crude oil is a good, low cost diluent, providing that a sufficient supply is available and that the heavy oil being diluted does not adversely affect the refinery acceptance of the mixture. Another way to reduce viscosity sufficiently for pipeline pumping is to heat the pipeline. This is generally done at pump (compressor) stations and works well. The process obviously entails added expense, although this cost may be mitigated by using the heat from gas-turbine-powered pumps to thin the oil.

Finally, the viscosity may be reduced through the use of water-in-oil emulsions. This method is being developed in Venezuela for the movement of Orinoco Oil Belt oils, a long distance to the nearest port in an area which lacks sufficient light oil and natural gas to provide viable alternatives.

Refining

The refining of petroleum is a combination of art, science, and technology that is beyond the comprehension of the non-specialist. However, it is apparent that heavy oil must be upgraded from about 8° API to at least 23° API to make it an acceptable feedstock for conversion to more desirable products. This upgrading can be done in three different ways: by carbon rejection (reducing the amount of carbon relative to the hydrogen content), adding hydrogen to the molecules, or upgrading the oil with neither carbon rejection nor the direct addition of hydrogen, usually through some form of catalysis (Table 10). Many of the methods were discussed during the Third International Conference on the Future of Heavy Oil and Tar Sands (United Nations, 1985) and the refining aspects of the conference have been reviewed by Parkinson (1985). Carbon rejection can be accomplished in the coker of a distillation unit or through solvent deasphalting. The coker is conventional but costly in terms of product, with as many as 30 of each 100 barrels of oil ending up as coke. Hydrogen addition can take many forms, with the general aim of keeping required pressures as low as possible and conversion to lighter products as high as possible. Most processes involve cracking and catalysis at some stage, that is, hydrogenation. Finally, processes are under development to provide upgrading without hydrogen. These involve the use of a catalyst. Most Canadian heavy crude oil ends up in United States refineries, mostly in the northern tier, though some is destined for the northern Rocky Mountains or California.

Leffler (1979) and Speight (1980) have given various cut temperatures, the distillation temperatures required for specific products. There is considerable variation, depending upon the feedstock and desired products but, in general, the common distillation fractions are:

Butanes and lighter	<90°F
Gasoline	30 - 355
Naphtha	30 - 400
Kerosine, stove oil*	400 - 550
Light gas oil*	400 - 600
Heavy gas oil	600 - 800
Vacuum gas oil	800 - 1100
Residuum	>1100

*The kerosine, stove oil, and light gas oil are often classed as the middle distillates.

Usually vacuum gas oil is not given separately in published analyses. For purposes of Table 1, the residuum is considered rather broadly to include anything boiling at about 1000°F or higher. The real value to a geologist, at least, of such distillation temperatures lies in providing a perspective for the thermal maturation of hydrocarbons in nature.

Capacities of refineries of the free world and of the United States and Canada are given in Table 10. These two countries possess one-third of the plants and nearly as much of the crude oil capacity. They also have about 40% each of vacuum distillation and thermal operations and 60% of catalytic cracking and catalytic hydrocracking and 40% of the catalytic hydrotreating. They also account for more than one-half the asphalt and hydrogen and 85% of the petroleum coke production. As of July 25, 1986, the United States was working at 81.2% of operable capacity with 12.5 million b/d of crude oil runs from a total capacity of 15.6 million b/d. On that date, United States refinery output was 6.9 million b/d of motor gasoline, 1.2 million b/d of jet fuels, and 3.4 million b/d of fuel~~s~~ oils, 0.8 million b/d being residual fuel oil.

Refiner's acquisition costs for crude oil in the United States are given in Table 11. These costs are well above world prices for crude oil but must include such items as transportation costs and are variously adjusted to suit the requirements of the producers.

A point has been made above that heavy crude oil and natural bitumen have much in common with the residua of lighter oils. This relationship is vital to both the United States and Canada but for different reasons; the former is in a very strong position worldwide in refining and the latter possesses an enormous resource of natural bitumen. The matter of refinery margins and crude oil price differentials is of utmost importance. Lundberg (1985) described the crude price differentials and their implications as of mid-1985. At that time, there was an enormous difference between the prices of the heavy crudes and the conventional light crudes, amounting to as much as $7.00 or $8.00 between Arabian Light and California San Joaquin Valley heavy. This was based largely on a refinery shortage and demand for bunker fuel and asphalt. The price differential has now disappeared. The Oil & Gas Journal carries a series on Gulf Coast refinery margins, the basis of which is described by Dudley, Killen, and Ory (1984). Regional refinery margins increased during the fourth quarter of 1985, from $0.34 in September to a loss of $2.18 in January. The deficit was $0.38 in February but has since recovered to $1.85 profit in June, the latest data available. These data reflect the fact that world crude supplies are becoming heavier and that the United States is in a strong position relative to the upgrading of 1000°F residuum and heavy oil.

Conclusions

Lohrenz and Pederson (1986) have placed a proper perspective on the relative values of finding, developing, and producing costs of petroleum. In the United States, the frontier areas have been diligently searched and found wanting. Therefore, the industry has turned to the known areas and sought ways to extract more oil from the ground through enhanced oil recovery and other more costly means, such as mining, tunneling, or horizontal wells. In Canada, the story has been much the same, with many geological successes, but too few economic successes. Each country is well endowed with heavy oil, which makes a substantial contribution to supply but is limited in future resources and which cannot provide the producing capacities needed in the future to offset the decline of production of conventional oil.

Actually, the average API gravity of the oil that is being produced decreases yearly, a factor pointed out in Energy Topics (1985) from U. S. Department of Energy data. There has been an accompanying increase in sulfur levels. The average United States crude imports shifted from 33.7° API and 1.0% sulphur in 1978 to 31° API and 1.3% sulfur by 1983. According to Energy Topics (1985), about 27% of 1984 imports were below 25° API but in 1977 only 5% had been. About 21% of 1984 imports were above 2.5% sulfur compared with only 4% in 1977. This can be explained in a number of ways, but such a decline places an increasing premium on countries with the refining capacity not only to process large volumes of oil in the face of a lowering of quality but to convert it into desirable products. For the present, the United States is dominant in refining operations, whereas, in western Canada, refineries are mainly tailored to local conditions. For the United States the matter of refining capacity may ultimately prove a far more important factor than domestic supply of crude oil. Obviously, the countries with the excess conventional oil supplies will become more and more desirous of the economic benefits of selling products, not just crude oil. Canada is well situated for the long term, with its enormous supplies of bitumen. The largest amounts of heavy crude oil and extra-heavy crude oil are in Venezuela, which is developing the capacity to upgrade and refine them. For the United States the long-term future must reside in shale oil, a considerably more complex operation than exploiting heavy oil or natural bitumen.

Most United States heavy crude oil is found in California, a place with a strong market and a well-developed infrastructure, so that its heavy oil supplies are mostly economic to produce, even at mid-1986 prices. California lacks only adequate refining capacity. Canada is far-sighted in supporting a heavy oil and natural bitumen industry with an eye to the future. The limiting factor in each country is a lack of heavy crude oil resource, coupled with their inherent low producing capacities. Unless prices continue to slide even lower and maintain the low level for a year or so, it is likely that the heavy crude oil segments of the refining industries will survive; most heavy oil production operations are more costly than conventional oil not under enhanced oil recovery.

For Canada, the principal problem is that of having a vast resource—the oil sand—that for the present is only marginally economic. The solution is time.

For the United States the problem is a lack of resource. Therefore, the solution is not time for a new resource to become economic—shale oil excepted—but to take advantage of a viable resource: in-place refining capacity and sophistication, and to enhance on this advantage, not lose it.

Heavy crude oil and natural bitumen are not ideal commodities to have, but they are superior to no resource at all, the fate of many nations. They are most easily likened to refinery residual, the material boiling above 1000°F. They are usually high in asphaltenes and the receptacles for most of the organometallic molecules. As a result they contain the bulk of the components undesirable to the refiner: nitrogen, oxygen, sulfur, vanadium, nickel. They are lacking in paraffins and low molecular weight components.

Therefore, it behooves the Canadians on the west to be patient, those on the east to import crude oil and build refineries; the Americans should solidify their position in the refining world, building on what they already have and on their superb infrastructure for moving products about, coupled with a seemingly insatiable public appetite for petroleum, preferably the cheaper, the better.

ON OPEC AND COAL

An Address By

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To The

International Oil & Gas
Markets Conference
Of The
Canadian Energy Research Institute
And The
Calgary Chamber of Commerce

Calgary, Alberta
September 16, 1986

My boss, Carl Bagge, whose name appeared on earlier programs and for whom I am substituting under duress, saw me off with instructions to deliver his best regards to his many friends here. He regrets greatly not being able to be here today in person. If he were, you would hear a different speech.

I should note that the duress is on Carl, not on me, for I told him I would not talk about acid rain.

Being invited to Canada to speak as a representative of the American coal industry and not using the forum to talk about our favorite topic of discord with our northern neighbors was almost more than Carl could understand.

I should add that this was not the cause of his heart attack. He is recovering handsomely from that; and, in fact, he returned to work yesterday on a limited schedule. That seems to be limited as in 20th Century Limited, the express passenger train.

In reviewing your program I see that I am the only coal man in what is otherwise a field dominated by oil and gas.

This is as it has always been; however, it is not as it should be, or will be.

The reason has nothing to do with condescending acknowledgement of so-called alternative energy sources among which coal is sometimes--if you will excuse me--lumped by oil and gas people.

And it has less to do with the occasional grudging-but-respectful nod to the energy source which fueled the industrial revolution and is now regarded by many otherwise alert minds as almost a relic of feudal times--as if coal were the energy equivalent of the Middle Ages, which laid the all-important foundation for the Renaissance of oil and the Enlightenment of gas which followed. I'm sure you find that analogy appealing.

Rather, the reason coal belongs here has to do with very modern history, and with the future outlook for the world price of crude oil. And I dare say there has been no topic more thoroughly discussed here--from the podiums and during the breaks--than the course of crude oil prices.

It borders on ridiculous understatement to say that energy markets have been transformed over the past decade.

Yet I am constantly amazed at how little appreciation exists for the way coal fits into this transformation; both for how oil prices have affected coal; and, even more importantly, for how coal--in turn--has affected oil prices, and for how it will continue to affect them.

The condescension, the grudging acknowledgement and the lack of appreciation call forth an image for the relationship between oil and coal that alternately haunts and teases my mind. I cannot put it aside. I do regret that it's a little off-color.

However, emboldened by the advice of some of my friends in the audience to tell it like it is, I will not hold back.

The thought is this: Coal is the bastard child of OPEC.

Coal is not just the child of OPEC, but the bastard child because neither party likes to acknowledge the unflattering relationship; and, as in all such cases, neither party can escape the consequences. The sire would have been better off without the bastard because such offspring often become ambitious brawlers.

So it is with oil and coal.

Not so very long ago--barely more than a decade--coal could have been characterized only as a dying industry, and in fact many described it as such.

Coal had seen one market after another lost to abundant and cheap oil and natural gas--from home heating to transportation to industrial steam.

This was true around the world. Where a coal industry existed, it was just holding on. Its reach was strictly local, and in most instances it was heavily subsidized.

By the early 1970s coal appeared to be doomed in its last remaining redoubt, the electric utility market, by two further threats.

First there was the promise of nuclear power, which was to be too cheap to meter. Then there was increasing concern for the environment led by a movement that sought to internalize coal's every identifiable externality, and then some--just to be sure.

Today--a bare decade later--the situation is much changed.

A new coal industry has been born--or reborn, if you will--for no other reason than OPEC's highly understandable but fateful dalliance with the events of 1973 and the return for more in 1979.

As is typical of dalliance, the immediate consequences were pleasant. The pain comes later, and, as the country song suggests, sometimes the pleasure ain't worth the pain.

Shakespeare--that great student of human nature and events--ascribed to the sons of dalliance an especially fierce composition and quality such as that seen in William the Conqueror.

William defiantly and proudly took the name Bastard. He also took Normandy. And then England.

So it is here. Coal, the bastard child of OPEC, has grown. His domain is no longer local. He is reaching worldwide to enlarge his portion of the estate, and to lay claim to as much of it as opportunity will present. He is an ambitious brawler--a William in every sense of the word.

OPEC ONE gave coal a start. But it was only with OPEC TWO that the consequences became evident, if not fully or widely recognized.

One consequence: Today there is a second world energy market--it is for steam coal. Before there was only one--for crude oil. Oil had the estate locked up.

The world oil market is still there, of course. And it is very much the larger market. But now it does have a competitor.

The reasons for the competitor's birth are not hard to understand.

It must not be forgotten that coal also provides Btu's.

Producers of oil like to value oil for oil, as do producers of coal for coal and--especially--producers of gas for gas.

And occasionally consumers can be dazzled into giving greater value than is deserved to the form of the Btu. But this usually doesn't last very long.

Btu's in the form of coal can be mined in the United States and loaded on a collier at Norfolk at about $35 a short ton, which is about $1.50 per million Btu's, or oil at roughly $9 a barrel.

Prior to 1979 the price of oil was not high enough to justify shipping steam coal from the United States to the rest of the world, much less high enough to justify the added cost of coal boilers.

However, the price was high enough to create nice prospects for coal within the United States. The prospects encouraged a lot of investment in what had been a moribund industry. This was the seed planted in the dalliance of OPEC ONE. We'll come back to that in a moment.

After 1979 the world price of oil was more than enough to remove any dazzle that oil possessed. And to provide the opportunity for coal to extend its reach worldwide.

Whether at Rotterdam or Yokohama, the price comparison was oil at $30 a barrel--more or less--while coal offered Btu's at the equivalent price of $12 a barrel.

The world responded accordingly; and the world steam coal market developed virtually over night. In 1985, 100 million more tons of steam coal--the equivalent of 2.5 million barrels of oil a day--crossed the seas than in 1978.

Like William of Normandy coal may start with a disadvantage, but it isn't that great.

Today Btu's flow to the world in the form of coal from the United States, from Australia, from Poland, from South Africa, from Canada and--most recently--from Colombia; and perhaps soon from China and India. They flow to Western Europe, to the Pacific Rim and to other, smaller, energy consuming regions.

At a total of 140 million tons--or 3.5 million barrels a day--the flow of coal Btu's is not as great as the flow of Btu's in the form of oil from the Persian Gulf and other oil producing countries to these same energy markets.

But it is just as real and steady, and it has been growing rapidly.

The impact is illustrated by British Petroleum's statistics on world energy use. I keep trying to disprove the contention that economists cannot make a point without a blackboard or a slide. But I haven't yet succeeded. And I am going to fail once again in that here today.

This slide shows what happened to world energy demand between 1979 and 1985.

WORLD ENERGY DEMAND

Change, 1979 to 1985
(Quads)

Region	Oil	Natural Gas	Coal	Hydro, Nuclear, Other	Total
IAC's	-14.2	-2.0	+ 4.5	+5.7	- 6
U.S.	- 5.5	-2.9	2.5	0.9	- 5
W. Europe	- 5.5	0.4	0.4	2.7	- 2
Other	- 3.2	0.5	1.6	2.1	+ 1
LDC's	2.7	2.3	2.8	2.2	+ 10
CPE's	.4	7.6	5.1	1.9	+ 15
World	-11.0	+8.0	+ 12.0	+9.0	+ 19

Take note that aggregate energy demand has increased, not decreased, thanks to growing demand in the LDC's and the Centrally Planned Economies. In these economies, demand increased for energy from all sources, although the increase in demand for oil at about three quads--or 1.5 million barrels a day--was the least of all.

A decline in demand was experienced only in the relatively free market economies of the Industrially Advanced Countries, but not all sources of energy experienced a decline of demand. Coal and the non-fossil sources experienced significant increases of demand. The substitution for oil was far greater than anyone expected because a Btu is just a Btu, and there is a huge market for steam.

In retrospect, it is easy to see why there is now surplus oil production, and why the price of oil has fallen.

The gains of coal, of nuclear power--which had a lot of pre-1973 momentum--and of conservation quickly explain why oil never reached the $60 a barrel once soberly predicted; and why it barely penetrated $30 on a serious basis.

These figures illustrate what some of us had come to doubt prior to 1979--elasticity is alive and well. However, it's a little slow to act sometimes.

A word needs to be said about the slowness of the response, at least as it pertains to coal, for much is revealed about world oil prices.

As a source of Btu's, coal is abundant relative to crude oil. In this lies coal's advantage. But it is also a less concentrated host for Btu's, and in this lies coal's disadvantage.

In economic terms, the lower concentration of Btu's means that the equipment required to extract usable Btu's from coal is more complicated and elaborate than that required to extract But's from oil or natural gas.

This, in turn, requires greater investment at the point of utilization quite apart from any environmental considerations.

The investment in equipment to get Btu's from coal will only be made when the expected difference in the price of Btu's from coal as compared to oil or gas is great enough to provide for the recovery--over the requisite period of time--of the greater up-front capital investment.

With respect to this disadvantage, I need only observe that OPEC has been an incredibly indulgent sire. They have provided more than enough incentive to transport Btu's in the form of coal to the furthest reaches of the globe; and to make the necessary up-front capital investment in coal-burning equipment.

Remember, coal can be loaded on a ship at Norfolk--the coal world's Ras Tanura--for the Btu equivalent price of $10 a barrel and landed at Rotterdam for $12 a barrel.

Add another $4-to-$5 a barrel--or even $8--for differential costs pertaining to initial capital investment, inland transportation and operating cost and what do you have?

You have a very visible competitor to oil for all uses outside internal combustion engines at any price over $20 a barrel.

Of course, the higher the price of oil over this level, the easier it is to justify the needed up-front investment in coal-burning facilities, and the quicker the substitution of coal for oil under boilers. This effect is demonstrated by the 12-quad gain for coal and the 12-quad loss for oil. Young William has grabbed 6 million barrels a day off the old man's once wholly owned preserve.

The price of oil, at which coal is substituted for oil in the steam market, resembles what the optimal price theorists like to call a backstop price. It is not the ultimate backstop of synthetic fuels--that is higher, as we all know.

But it is a good intermediate backstop that--for present and all practical purposes--poses a significant problem for OPEC. It is an upper limit for the foreseeable future on oil prices.

In going up, oil prices have found a limit. What about the downside, where we now find ourselves?

Since 1979, coal has been substituting for oil around the world. And in every use the capital investment necessary to burn coal has only recently been made: The capital is sunk.

The important thing about capital is that it doesn't disappear even if the prospective return which called it into place does.

Because the capital is sunk, it is more economical to continue using coal even if oil prices are lower than the $15-to-$20 a barrel required to call forth the investment. It is with market share as it is with some forms of dalliance: What is lost is never easily, if ever, regained.

There has been--so far--no pell mell rush from coal to oil as oil prices have declined. Going from oil to coal was slow and hard to do because of the required return on the capital investment. Going from coal back to oil is surprisingly no easier because the capital is sunk.

On both the up and the down sides, the greater capital-intensity of coal use creates an inelasticity within certain oil price ranges, beyond which there seems to be nothing but elasticity.

That price range is defined on the lower end by the Btu-equivalent price of coal. The upper end is that which creates the expectation that the greater capital investment for coal can be recovered.

During the past decade, we have--with rising oil prices--traversed that range of elasticity, crossed the threshold which calls forth the investment in coal-using equipment, and found the elasticity beyond.

Now--with falling oil prices--we are again traversing that range of inelasticity, and we can anticipate the lower limit and the elasticity that lies just as surely beyond the lower threshold.

For to say, as I have, that falling oil prices have had no appreciable impact on coal use as yet, is not to say that they cannot.

I don't kid myself, so I won't try to kid you. There is a point to which the price of oil can fall that is low enough to have a significant impact on coal.

Even the great William could have been turned away from England if--

If Harold had not been otherwise occupied;

If Harold had recognized the real challenge soon enough;

And if Harold had been able to bear the pain of acting first.

The question is, how much pain is OPEC willing to take to turn back this William it spawned; how much pain can the other producers take to throttle this son of dalliance?

In the present instance, the point at which coal is affected is not the $15-to-$20 a barrel range where oil lost market share. This price may prevent the emergence of subsequent Williams, but it will not quell the brawler that is coming on.

The price of quelling coal starts at $12-to-$15 a barrel. The price of subduing the bastard completely is $5-to-$6 a barrel, the pre-1973 price in today's dollars.

I need not tell anyone in Calgary that going to $5 a barrel--and staying--will hurt far more than anyone can imagine.

But there is a catch, and hope. As oil prices fall below $15 a barrel, oil begins to substitute for coal in the most costly steam markets.

This process will accelerate quickly as the price goes below $10, and--in doing so--we find the elasticity and demand to stablize oil prices. That elasticity appears only as oil prices fall below the price of Btu's from coal.

Because of the sunk capital, the price at which the market is recaptured is much lower than the prices at which the market was lost. Was the pleasure worth the pain?

I have suggested a number of things that should be summarized at this point.

Coal's greater capital-intensity in use, it's substitutability for oil in uses outside the internal combustion engine, and its relative abundance create certain limits on oil prices.

These limits reflect the price of Btu's from coal on the lower end; and, on the upper end, they reflect that plus the appropriately amortized cost of coal-using equipment.

In a word, coal prices will drive oil prices. If so, what then can be said about coal prices?

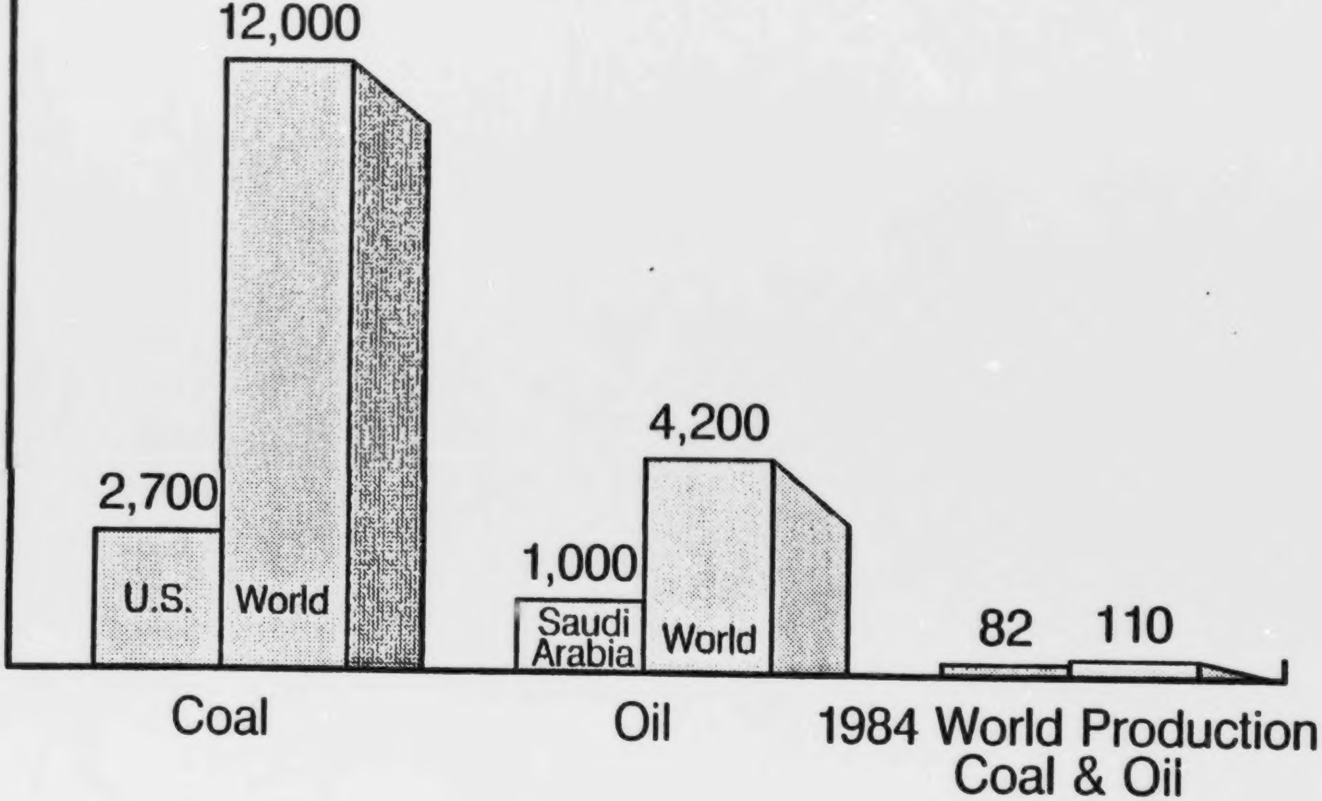
Two points must be kept in mind. First, the United States is the Saudi Arabia of the world steam coal market. And--equally important--the price of producing coal in the United States has been falling steadily for 10 years.

These things require some tying together, and this means some more slides.

The current state of geologic knowledge--whose practitioners are as bad as economists in appearing definitive about what is not particularly well-known--is that three times as many Btu's are available to the world in coal as in oil, as this slide shows.

WORLD PROVED RESERVES, COAL & OIL

U.S. Coal vs. Saudi Arabia Oil
(Quads)



Proved recoverable world reserves of coal stand at 12,000 quadrillion Btu's. Oil is 4,200 quads. There are a lot more quads in oil than some people like to recognize. But there are vastly more in coal.

In coal, the American industry occupies the same position that Saudi Arabia holds in oil. Both hold about 25 percent. And U.S. reserves constitute about half the free world's reserves.

As do the Saudi's in oil, we have plenty of competition in the new world steam coal market. Canada, Columbia, South Africa, Australia, Poland and others all are scrapping for a share.

And, again, as with the market for crude, the U.S. price for coal is the one all other producers attempt to beat.

Just as surely as crude pumped aboard at Ras Tanura is the benchmark for world oil prices, so is high-grade American coal loaded at Norfolk the price-setter for world steam coal. Reserve positions make both so.

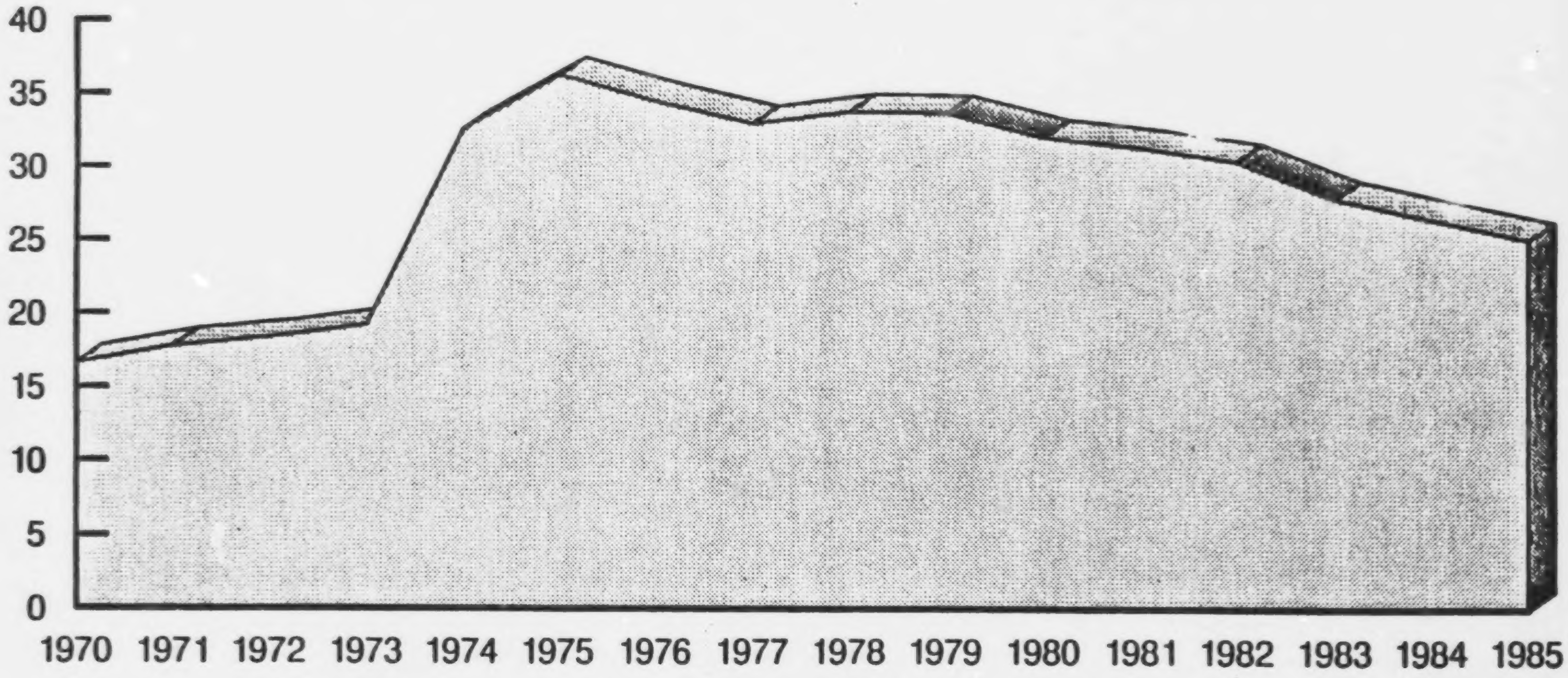
And here is where the consequence of the seed planted by OPEC ONE becomes very important.

Due to post-73 investment in the American coal industry the price is a moving target--for other coal producers and for oil.

Not only is it moving, it is falling. This is the least-noted and most under-appreciated fact in energy analysis. This slide shows the trend.

COAL PRICES

Average U.S., FOB Mine (1985 Dollars, Short Tons)



In real terms, the mine-mouth price of U.S. coal is one-third lower today than it was in 1975. There was a big run-up of coal prices in 1974. This established an adequate return to the factors of production. But since then the price of coal has declined 3.6 percent a year in real terms.

The cause is significant and continuing--I emphasize continuing--productivity gains within a very competitive industry.

Since 1978, productivity gains in the American coal industry have averaged 7 percent per annum. This has been more than enough to provide both a decent return to the factors of production and lower-priced energy to consumers.

These lower prices reflect not the benevolent instincts of producers but the harsh realities of industrial structure in the American coal industry. There are an estimated 3,000 firms in the American industry, and the largest producers are not really very large.

The largest accounts for only 7 percent of 1985 production. By a common measure of concentration the four largest firms produced 19 percent of the industry's output in 1985. Only 13 years earlier, in 1972, the four largest produced 30 percent.

In being reborn and growing, the American coal industry is becoming more competitive, not less so.

This highly competitive industrial structure means there is no excess fat in the industry, and no respite for producers. Competition within the industry--forget about competition with oil--forces gains in productivity. These gains make coal ever more competitive with oil.

As a result, the price of the coal which has become the marker coal reflects only the cost of production. Because of abundant reserves, coal cannot and will not command a scarcity premium. And because of competition, productivity gains are delivered directly to the customer. Thus the steady decline in real prices.

Competition and increasing productivity have driven the American coal industry, not the price of oil. So much for Btu-parity pricing. It hasn't existed, and the market won't let it happen.

These circumstances have clear implications for energy prices.

If oil prices are limited--both ceiling and floor--by the price of producing and using Btu's from coal; and,

If the world price of coal depends on the cost of production and shipment from the United States; then, The world price of energy had to fall, and it will be under continuing downward pressure from coal. If it's painful for oil to quell this William today, it will not be less so tomorrow. The bastard grows stronger and stronger.

What will the world price of coal ultimately be under continuing productivity gains?

I dare not predict; but on the flight here, curiosity did cause me to calculate the indicated price of coal 20 years hence on the assumption that the productivity gains of the last seven years continued.

I assigned no scarcity value to coal--who could with 12,000 quads in mind ?--and assumed no change in industrial structure.

The result of my calculation was coal at $16.64 a ton in the year 2006 in today's dollars. That's 74-cents the million Btu's, or oil at about $4.40 a barrel.

Even I find this hard to accept although I find no flaw in the logic or the computation. If I take the assumptions with a grain of salt, even if the productivity gains are halved or quartered, it means coal will stay in the Btu competition, and it will be a fierce competitor.

Coal--like the most famous son of dalliance who proudly called himself William Bastard--cannot be sent easily or gently away once he is called forth.

You may have been a party to the dalliance that created him;

Or, more likely, you were only an incidental beneficiary of it;

And you may not like the result.

But the bastard is coming to the party whether the rest of the family likes it or not, whether invited or uninvited. And he'll find his place at the table. You have no choice now but to live with him.

As a representative of that less noted--but not less notable--branch of the energy family, I appreciate this opportunity to speak to you about how things should be, and will be, if given half a chance. The formal invitation and the listing of my name on the printed program are especially appreciated.

And I hope I have not disappointed you by not talking about acid rain. There is more to coal than acid rain. That's a point that bears noting, and repeating, in Canada, as elsewhere.

If any of you look upon coal as an upstart pretender or a mere alternative, think about the 12 quad coal-oil exchange of the last six years. If any of you look on coal as a quaint relic of the energy Middle Ages, think about the sunk capital, the gains in productivity and the 12,000 quads of reserves. These Btu's deliver light--and enlightenment--to users.

In closing, I ask your indulgence for a slight tampering with some appropriate lines from Shakespeare's King Lear.

"Why bastard? Wherefore base? When my dimensions are as well compact,

"My Btu's as generous, and my Btu's as true, as any energy will issue.

"I grow, I prosper;

"Now, gods, stand up for bastards!"

Keep in mind that, if you dally, the ultimate consequence is often a dilly. This ultimate consequence is inescapable: Coal is here. Coal is claiming a significant market. And coal is ready to take whatever becomes vulnerable--just as William took England.

AN OIL PIPELINER'S PERSPECTIVE

BY

R. Glen Caughey, Vice-President, Projects
Interprovincial Pipe Line Limited

A Paper for Presentation at
The International Oil & Gas Markets Conference
Calgary Convention Centre
September 16, 1986

Introduction

Mr. Moderator, Ladies and gentlemen, it is a pleasure to be attending and to take part in the International Oil & Gas Markets Conference.

My part on this afternoon's panel is to provide an oil pipeliner's perspective on some of the developments in the North American oil industry.

Background On Interprovincial

As a start, it might be appropriate to provide some background on Interprovincial, some of the things which we have done, activities currently underway and a brief view of future developments as we currently foresee them.

Interprovincial Pipe Line Limited, together with its United States subsidiary, Lakehead Pipe Line Company, Inc. operates one of the longest liquid hydrocarbon pipeline systems in the western hemisphere.

The system, which extends over 3,700 kilometres (2,300 miles) and includes almost 11,000 kilometres (6,800 miles) of pipeline, provides a vital transportation link for the movement of liquid petroleum resources from oil producing areas of Western Canada to refining centres and markets in Eastern Canada and the Mid-Western United States.

THE COMPANY ALSO OWNS AND OPERATES THE NORMAN WELLS PIPELINE, A 305MM (12") LINE EXTENDING SOME 860 KILOMETRES (539 MILES) FROM NORMAN WELLS IN THE NORTHWEST TERRITORIES TO ZAMA, ALBERTA.

THROUGH LPL INVESTMENTS INC. WE HOLD A 35% INTEREST IN FRONTIER PIPELINE COMPANY (A WYOMING GENERAL PARTNERSHIP), WHICH OWNS AND OPERATES A 405 MM (16") CRUDE OIL AND CONDENSATE PIPELINE WHICH RUNS 467 KILOMETRES (290 MILES) FROM THE OVERTHRUST BELT REGION OF SOUTHWESTERN WYOMING AND SOUTHEASTERN UTAH TO CASPER, WYOMING.

OUR STRATEGIC GOAL IS TO OPERATE "AN EFFICIENT AND PROFITABLE LIQUID HYDROCARBON PIPELINE SYSTEM MODIFIED AND EXPANDED TO MEET CURRENT AND FUTURE INDUSTRY NEEDS". PIPELINING IS OUR MAIN OR CORE BUSINESS AND FOR THE FORESEEABLE FUTURE WILL REMAIN OUR NUMBER ONE PRIORITY. HOWEVER, WE HAVE CONCLUDED THAT OPPORTUNITIES WITHIN OUR CORE BUSINESS OVER THE SHORT TO MEDIUM TERM COULD BE LIMITED. ACCORDINGLY, WE DECIDED TO ALSO DIVERSIFY OUR ACTIVITIES TO ENSURE FINANCIALLY ATTRACTIVE LONG TERM CORPORATE GROWTH.

FOR THE PAST FOUR YEARS, THE COMPANY EXAMINED THE POTENTIAL ACQUISITION OF AN OIL AND GAS COMPANY IN ORDER TO BROADEN OUR BASE OF OPERATIONS. IN AUGUST, INTERPROVINCIAL AND HIRAM WALKER RESOURCES LIMITED ANNOUNCED THE SIGNING OF AN AGREEMENT WHEREBY INTERPROVINCIAL WILL PURCHASE THE SHARES OF HOME OIL COMPANY LIMITED FOR APPROXIMATELY $1.1 BILLION.

WE BELIEVE THIS IS A VERY SIGNIFICANT STEP FOR THE COMPANY TO TAKE IN FULFILLING ITS CORPORATE DIVERSIFICATION GOAL. IN THESE TIMES WHEN GLOOM AND DOOM PREVAILS THROUGH MUCH OF THE OIL AND GAS INDUSTRY IN WESTERN CANADA AND ELSEWHERE, WE TRUST THIS BOLD MOVE WILL BE RECOGNIZED AS OUR BASIC VOTE OF CONFIDENCE IN THE FUTURE OF CANADIAN HYDROCARBON RESOURCES.

WE ARE CONVINCED THAT THE INDUSTRY WILL RECOVER IN THE FUTURE AND ARE DEDICATED TO LONG TERM DEVELOPMENT OF PIPELINE FACILITIES RELATED TO NATURAL RESOURCE PRODUCTION FROM THE WESTERN SEDIMENTARY BASIN AND FROM ELSEWHERE IN CANADA AS WELL.

INTERPROVINCIAL TAKES PRIDE IN OPERATING A COST EFFECTIVE, LONG DISTANCE, HIGH VOLUME PIPELINE SYSTEM. FOR EXAMPLE, IN 1985 WHICH IS THE LAST YEAR WHEN COMPLETE DATA WAS AVAILABLE FOR THE 30 PIPELINE SYSTEMS SURVEYED, THE IPL/LPL CONSOLIDATED SYSTEM WAS THE MOST COST EFFICIENT. IN THAT YEAR OUR CONTROLLABLE AND TOTAL SYSTEM COSTS COMPARED AS FOLLOWS:

	¢ U.S. PER 100M^3 - KM	
	CONTROLLABLE (1)	TOTAL 2
IPL/LPL SYSTEM	7.8	13.4
COLONIAL SYSTEM	8.5	15.0
EXPLORER SYSTEM	9.8	17.8
TRANS MOUNTAIN SYSTEM	14.3	22.1
THE HIGHEST COST SYSTEM	78.1	97.9

(1) CONTROLLABLE COSTS INCLUDE: FUEL/POWER; MAINTENANCE; GENERAL; OTHER.

(2) TOTAL COSTS INCLUDE: CONTROLLABLE; DEPRECIATION; TAXES; INTEREST.

A review of our 1985 annual report indicates that after tax earnings totalled $139 million; of this Canadian pipeline operations including Norman Wells contributed $28 million or 20%, while U.S. pipeline operations accounted for $65 million or 46.8%. In 1983, Canadian pipeline operations contributed approximately 26.8% of earnings, while U.S. pipeline operations accounted for 53.6%.

The reason for mentioning this is to demonstrate the importance of Lakehead earnings to Interprovincial and to emphasize that we are vitally concerned with, involved in, and affected by the development of crude oil and petroleum products markets in the North American context.

The Pace Of Change

We are living in fast changing times. In our view crude oil has become an international commodity with a high likelihood that in the future it will experience wide swings in value each year. For example, in 1987 we can easily envision a scenario where the price for marker crude could fluctuate between $10 and $20 U.S./bbl. Thus producers, refiners and pipeliners must be flexible; better understand; and be prepared to respond to; the factors affecting each segment of the industry. In my view these

CONSIDERATIONS SHOULD INCLUDE REGIONAL, NORTH AMERICAN AND ULTIMATELY GLOBAL FACTORS RELATING TO KEY ELEMENTS SUCH AS; COSTS (FINDING, PRODUCTION, GOVERNMENT ROYALTIES AND TAXES, TRANSPORTATION CHARGES); SUPPLY AVAILABILITY AND QUALITY; AND DEMAND INCLUDING AN ASSESSMENT OF HOW TRADITIONAL MARKETS ARE AFFECTED BY COMPETITION FROM OTHER FUELS AND CRUDE SUPPLIERS.

NO LONGER CAN WE AFFORD THE LUXURY OF PLOTTING STEADILY INCREASING CRUDE OIL PRICES YEAR OVER YEAR; OR EXPECT INCREASED MARKET PENETRATION AND GROWTH; OR IN INTERPROVINCIAL'S CASE BE IMMUNE FROM THE EFFECTS OF INTERNATIONAL COMPETITION IN OUR KEY MARKETS IN EASTERN CANADA AND MIDWESTERN U.S. (MINNEAPOLIS-ST. PAUL - CHICAGO).

HOPEFULLY THE WORST IS BEHIND US, FOR 1986 AT LEAST, AS DURING THE PAST MONTH CRUDE PRICES BROKE THE $CDN 20.00/BARREL LEVEL AFTER TOUCHING A LOW OF $CDN. 14.00 - 16.00 IN MID-JULY. REMOVAL OF THE PGRT EFFECTIVE OCTOBER 1, 1986 WILL ALSO ASSIST THOSE PRODUCERS WHO WOULD OTHERWISE HAVE HAD TO PAY IT.

PERHAPS A QUOTE FROM THE STANDING SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES REPORT, ENTITLED: "OIL MARKETING: 1986" IS APPROPRIATE AT THIS POINT;

> "THE RECENT DRAMATIC SLIDE IN WORLD OIL PRICES HAS CONFIRMED ONCE AGAIN THAT THE ONLY CERTAINTY IN THE INTERNATIONAL PETROLEUM MARKET IS THE CERTAINTY OF CHANGE".

SYSTEM EXPANSION

I WOULD NOW LIKE TO COMMENT BRIEFLY ON SYSTEM EXPANSION. INTERPROVINCIAL IS CURRENTLY IN THE PROCESS OF COMPLETING CONSTRUCTION OF PHASE II AND THE FIRST PART OF PHASE III OF A $410 MILLION THREE-PHASE EXPANSION PROGRAM THAT COMMENCED IN 1984. PHASE III WILL BE COMPLETED IN THE THIRD QUARTER OF 1987. THIS CONSTRUCTION PROGRAM IS A CARRY-OVER FROM THE HEADY DAYS WHEN OIL WAS AT $30.00 U.S. PER BARREL AND CLIMBING. HOWEVER, IN JULY AND AUGUST EVEN THOUGH CRUDE PRICES WERE AT LOW LEVELS, INTERPROVINCIAL HAD TO APPORTION INITIAL TENDERS FOR SHIPMENTS ON LINES 2 AND 3.

OUR PHASE III CONSTRUCTION PROGRAM RECEIVED NATIONAL ENERGY BOARD APPROVAL THIS SPRING AFTER A PUBLIC HEARING CONDUCTED IN FEBRUARY 1986. WE HAD WIDESPREAD INDUSTRY SUPPORT FOR THE EXPANSION PROGRAM BASED ON THE FAIRLY OPTIMISTIC VIEW HELD AT THE TIME THAT PRICES WOULD TREND UP AGAIN EARLY IN THE YEAR AND PRODUCTION OF HEAVY CRUDE OIL AND BITUMEN WOULD CONTINUE TO INCREASE.

PHASE III INVOLVES CONSTRUCTION OF SOME 540 KILOMETRES (340 MILES) OF 508MM (20") LINE, AND 30 KILOMETRES (18 MILES) OF 1,219MM (48") LINE; FIFTEEN PIPELINE CROSSOVERS AT VARIOUS LOCATIONS; 27 NEW PUMPING UNITS AND PUMPING UNIT CHANGES AT 19 EXISTING STATIONS. WE ARE PLEASED TO REPORT THE CONSTRUCTION IS WELL UNDERWAY AND COSTS ARE COMING IN UNDER THE ORIGINAL ESTIMATE.

RATE APPLICATION

I WOULD BE REMISS IF IN PASSING I DID NOT MENTION, (AT LEAST FOR OUR SHIPPERS AND PRODUCERS THAT ARE HERE TODAY), THAT THE COMPANY'S CLASS 3 RATE APPLICATION FOR NEW TOLLS TO BE EFFECTIVE FOR 1987 WAS FILED WITH THE NATIONAL ENERGY BOARD SEPTEMBER 5TH. BEING A REGULATED TRANSPORTER, THIS APPLICATION AND THE RESULTANT NEB HEARING WILL PROVIDE A PUBLIC FORUM TO REVIEW KEY ASPECTS OF THE COMPANY'S OPERATIONS AND THE TARIFFS AND TOLLS UNDER WHICH SERVICE IS PROVIDED IN CANADA.

INDUSTRY TASK FORCE

INCREDIBLE AS IT MIGHT NOW SEEM, IN JANUARY 1986 WE STARTED DISCUSSIONS WITH AN INDUSTRY TASK FORCE COMPOSED OF REPRESENTATIVES FROM THE CANADIAN PETROLEUM ASSOCIATION (CPA) AND THE INDEPENDENT PETROLEUM ASSOCIATION OF CANADA (IPAC) TO PREPARE FOR AND CONSIDER A PHASE IV EXPANSION PROGRAM. AT THAT TIME WE TARGETED DESIGN COMPLETION FOR THIS FALL FOR PROMPT APPLICATION TO THE NATIONAL ENERGY BOARD WITH CONSTRUCTION ANTICIPATED IN 1987 AND 1988.

PRICE SCENARIOS

IN LATE JANUARY AND EARLY FEBRUARY, WE DEVELOPED THE THREE PRICE SCENARIOS WHICH ARE SHOWN ON SLIDE 1 IN AN ATTEMPT TO PROVIDE AN ENVELOPE FOR CONSIDERING FURTHER FACILITIES EXPANSION ALTERNATIVES.

IN THE MEANTIME, THE NATIONAL ENERGY BOARD STAFF AND OTHERS HAVE ALSO ATTEMPTED TO PREDICT FUTURE PRICES AS SHOWN ON SLIDE 2. ALSO SHOWN IS AN OVERLAY OF OUR THREE PRICE SCENARIOS:

SUPPLY

- SLIDE 3 SHOWS THE SUPPLY OF LIGHT AND EQUIVALENT AVAILABLE FOR EACH PRICE SCENARIO.

- SLIDE 4 OUTLINES VOLUMES OF BLENDED HEAVY OIL AND BITUMEN.

VOLUMES TO BE TRANSPORTED BY IPL

- SLIDE 5 OUTLINES OUR FORECAST OF NET PRODUCTION AVAILABLE TO INTERPROVINCIAL UNDER EACH SCENARIO.

- SLIDE 6 INDICATES THE EXCESS OR SHORTFALL IN CAPACITY THAT WILL OCCUR UNDER THE THREE PRICE SCENARIO'S PRODUCTION PROFILES AFTER COMPLETION OF THE PHASE III EXPANSION PROGRAM.

UNDER PRICE SCENARIO # 1 WE WOULD CERTAINLY NOT EXPAND THE SYSTEM AT ALL IN THE FORSEEABLE FUTURE. WE HAVE ASSUMED THAT OIL FROM THE MACKENZIE DELTA, BEAUFORT SEA AREA WILL COME ONSTREAM IN 1995 UNDER THE HIGH PRICE SCENARIO 3 AND IN 1998 UNDER SCENARIO 2.

HEAVY OIL EXAMPLE

TO GAIN A FURTHER PERSPECTIVE OF THE DIFFICULTIES WE HAVE EXPERIENCED IN OBTAINING MEANINGFUL PRODUCTION AND MARKET DATA FOR SYSTEM DESIGN, LET'S EXAMINE SOME DETAILS OF THE HEAVY CRUDE OIL AND BITUMEN PRODUCTION ESTIMATES UNDER THE CPA/IPAC SCENARIOS AND IN LIGHT OF PAST INDUSTRY SURVEYS.

FIRSTLY, SOME HISTORY OF HEAVY OIL AND BITUMEN FORECASTING AS WE AT INTERPROVINCIAL HAVE BEEN ABLE TO DEVELOP IT BASED ON INFORMATION PROVIDED BY APPROPRIATE PRODUCERS. LINE 1 OF SLIDE 7 SHOWS THE PRODUCTION PROFILE WE DEVELOPED FROM AN INTENSIVE SURVEY CONDUCTED IN EARLY 1984. ALSO SHOWN ON LINE 2 IS THE ESTIMATE CONTAINED IN THE NATIONAL ENERGY BOARD'S 1984 REPORT ON ENERGY RELEASED IN SEPTEMBER 1984.

IN THE SPRING OF 1985, INTERPROVINCIAL AGAIN CANVASSED THE HEAVY OIL PRODUCERS AND OBTAINED SLIGHTLY HIGHER VOLUMES LINE 3, SLIDE 7 AS ADDITIONAL PROJECTS WERE CONTEMPLATED. THIS LEVEL WAS CONFIRMED BY A CPA STUDY COMPLETED IN OCTOBER 1985 WHICH WAS USED BY CPA TO EVALUATE THE PROJECTIONS OF BITUMEN AND HEAVY OIL PRODUCTION CONTAINED IN OUR PHASE III FACILITIES APPLICATION.

BECAUSE OF THE SIZE AND NUMBER OF NEW PROJECTS BEING PLANNED LATE LAST YEAR, INTERPROVINCIAL UNDERTOOK A FURTHER IN-DEPTH MAIL SURVEY TO DETERMINE PRODUCER INTENTIONS IN DECEMBER 1985 AND OBTAINED THE VOLUME ESTIMATES SHOWN AT LINE 4 ON SLIDE 7, A RATHER SIGNIFICANT INCREASE, BASED ON THE OPTIMISM THAT PREVAILED AT THE TIME.

THE SCENARIO WORK WHICH WE DID EARLIER THIS YEAR WITH CPA/IPAC MEMBERS RESULTED IN THE MUCH LOWER RANGE OF PRODUCTION ESTIMATES SHOWN ON SLIDE 7 (LINES 5, 6 AND 7).

VIEWED AS A COMPOSITE (SLIDE 8) THIS LARGE VARIATION IN ESTIMATES OF POSSIBLE PRODUCTION LEVELS DURING A RELATIVELY SHORT TIME PERIOD ILLUSTRATES ONE OF THE DIFFICULTIES WE AS PIPELINERS HAVE TO ADDRESS IN DETERMINING HOW TO; HOW MUCH TO; WHERE TO; AND WHEN TO; EXPAND OR MODIFY OUR PIPELINE SYSTEMS; TO ANTICIPATE AND MEET OUR SHIPPERS' REAL OR PERCEIVED NEEDS.

DILUENT

UP TO NOW WE HAVE ONLY EXAMINED THE PRODUCTION PORTION OF THE BITUMEN AND HEAVY CRUDE OIL SUPPLY EQUATION. BECAUSE OF PIPELINE FLOW CHARACTERISTICS; PUMP DESIGN AND OPERATING CONDITIONS, BATCH INTEGRITY REQUIREMENTS; ETC. ARE AFFECTED BY THE GRAVITY AND VISCOSITY OF THE OIL BEING PUMPED WE INSIST THAT BITUMEN AND HEAVY CRUDE SHIPPERS BLEND DILUENT WITH THEIR MATERIALS TO ENSURE VISCOSITY OF THE MIX DOES NOT EXCEED 250 CENTISTOKES AT THE PREVAILING RECEIPT POINT LINE TEMPERATURE.

CURRENTLY, CONDENSATE IS THE MOST COMMONLY USED DILUENT. FOR EXAMPLE, COLD LAKE BITUMEN HAS AN API GRAVITY OF ABOUT 10.2 AND WHEN BLENDED FOR SHIPMENT THROUGH OUR SYSTEM THE MIX CONTAINS 30 - 35% CONDENSATE (2:1). THE AVERAGE DILUENT LEVEL FOR ALL BITUMEN AND HEAVY CRUDE SHIPPED IS CURRENTLY IN THE ORDER OF 26 - 28% OF THE BLENDED MIX. OUR STUDIES (SLIDE 9) SHOW SHORTAGES OF CONDENSATE WILL OCCUR IN VARYING DEGREES DURING THE NEXT FEW YEARS DEPENDING ON THE PRICE SCENARIO ASSUMED.

IN COMPLETING OUR VOLUMETRIC FORECASTS WE HAVE ASSUMED THAT ANY CONDENSATE SHORTFALL WILL BE MADE UP FOR WITH NAPHTHA OR OTHER REFINERY PRODUCED DILUENT AND WILL BE PRODUCED IN CURRENTLY INSTALLED CAPACITY IN ALBERTA USING LIGHT CRUDE OIL AS FEEDSTOCK. WE ADMIT THIS IS A SIMPLISTIC SOLUTION, HOWEVER, WE WILL CONTINUE TO EXPLORE OTHER ALTERNATIVES WITH PRODUCERS, SHIPPERS AND REFINERS INCLUDING;

- BLENDING WITH LIGHT CRUDE
- CONDENSATE RETURN BY RAIL OR PIPELINE
- INSULATED AND HEATED LINE
- OIL IN WATER EMULSIONS.

HEAVY OIL MARKETS

FROM A PIPELINER'S PERSPECTIVE, THE REMAINING AND PERHAPS MOST CRITICAL PORTION OF THE PIPELINE EQUATION DEALS WITH MARKETS AND MARKETING. THE USE OF MARKET INFORMATION (SIZE/LOCATION/PRICE SENSITIVITY/COMPETITION) FOR EVALUATING FORECASTS OF HEAVY OIL AND BITUMEN PRODUCTION AND SHIPMENT FORECASTS PROVIDES A REAL WORLD DIMENSION THAT HAS SOMETIMES BEEN OVERLOOKED BY OVER-ZEALOUS PRODUCERS AND PRODUCTION DEPARTMENTS. SINCE OIL PRICES WERE DEREGULATED IN CANADA ON JUNE 1, 1985, IT'S PRODUCER NETBACKS THAT SUFFER IF PRICE REDUCTIONS ARE NECESSARY TO MEET COMPETITION, GAIN NEW MARKETS OR IF PIPELINE TARIFFS INCREASE.

OUR CURRENT FORECASTS OF MARKETS FOR BITUMEN AND HEAVY CRUDE OIL ARE OUTLINED ON SLIDE 10. YOU WILL NOTICE THAT ONE OF THE LARGEST POTENTIAL MARKETS DESIGNATED "CHICAGO SOUTH" WHICH REFERS TO THE WOOD RIVER AREA SOUTH OF CHICAGO. WE HAVE ASSUMED UP TO 50,000 BARRELS PER DAY COULD REASONABLY BE MARKETED IF CANADIAN PRODUCERS WERE WILLING TO ESTABLISH THE NECESSARY MARKET CLEARING PRICES. IN OUR VIEW AT THE "RIGHT PRICE" A TOTAL MARKET FOR CANADIAN HEAVY CRUDE IN THE WOOD RIVER AREA IS CURRENTLY IN THE ORDER OF 100 - 120,000 B/D. UNFORTUNATELY WE ARE NOT YET CONNECTED TO THIS MARKET AND WE WILL NEED SHIPPER THROUGHPUT COMMITMENTS BEFORE THE NECESSARY CAPITAL INVESTMENT CAN BE JUSTIFIED.

Until crude oil supply and price fluctuations stabilize and prices actually increase, we feel it will be difficult to obtain such commitments from Canadian heavy oil producers so that the Wood River area can be served as an "Incremental" or even an "Alternate Market":

Competition

In our view the Wood River area will be one of the markets which will prove the intentions and test the resolve of Canadian heavy crude oil and bitumen producers. In 1985 the following supply sources vied for this market;

	VOLUME (1,000 B/D)	SHARE (%)
DOMESTIC	332	78.7
MEXICO	80	11.8
SOUTH AMERICA	14	3.3
OTHER OFF SHORE	26	6.2
	422	100.0

Construction of the 30" diameter All American Pipeline is well under way. When completed next year this heated heavy oil line has the potential to land up to 300,000 B/D of California Continental Shelf heavy oil production in Texas.

IN ADDITION, THE PACIFIC TEXAS PIPELINE IS IN THE PROPOSAL STAGE. THIS 42" DIAMETER LINE HAS A TARGET COMPLETION DATE IN 1988 AND COULD TRANSPORT UP TO 900,000 B/D OF ANS AND OTHER CRUDES FROM LONG BEACH, CALIFORNIA TO MIDLAND, TEXAS.

BOTH THESE FACILITIES WILL PROVIDE DOMESTIC U.S. SUPPLIES THAT COULD COMPETE WITH CANADIAN PRODUCERS AND OTHERS FOR THE WOOD RIVER MARKET.

I TRUST THESE BRIEF COMMENTS ABOUT ONE OF THE MANY AREAS WE WOULD LIKE TO SERVE WILL HELP TO ILLUSTRATE THE TYPE OF UNCERTAINTIES WE HAVE TO CONSIDER IN SATISFYING OUR STRATEGIC GOAL OF "EXPANDING THE PIPELINE SYSTEM TO MEET CURRENT AND FUTURE INDUSTRY NEEDS".

OTHER ACTIVITIES

PERHAPS I CAN PROVIDE A FURTHER "OIL PIPELINER'S PERSPECTIVE" BY TOUCHING BRIEFLY ON SOME OF THE OTHER ACTIVITIES AND STUDIES WE ARE CURRENTLY INVOLVED WITH;

- EVALUATION OF PIPELINE ALTERNATIVES FOR MACKENZIE DELTA-BEAUFORT SEA PRODUCTION
- EVALUATION OF FLOW IMPROVERS AND OIL IN WATER EMULSIONS
- LOWERING HEAVY CRUDE VISCOSITY WITH HEAT AND INSULATED PIPELINES

- POSSIBLE CONSTRUCTION OF NGL STORAGE AND TERMINAL FACILITIES AT EDMONTON, SUPERIOR AND SARNIA

- POSSIBLE CONVERSION OF THE MONTREAL LINE TO HIGH VAPOUR PRESSURE SERVICE

- POSSIBLE REVERSAL OF THE MONTREAL LINE IN THE EARLY TO MID-1990'S

- POSSIBLE INVOLVEMENT IN WATER PIPELINES

- CONTINUING TO STUDY THE FEASIBILITY OF DEDICATING A SEPARATE LINE TO MOVE HIGH VISCOSITY CRUDES

- INVESTIGATING FEASIBILITY OF CONSTRUCTING A NEW RECEIPT POINT AT CHICAGO, ILLINOIS SO CRUDE FROM U.S. OR OFFSHORE SUPPLIERS CAN BE DELIVERED TO THE LPL/IPL SYSTEM.

CONCLUSION

IN CLOSING I WOULD LIKE TO STRESS THE FOLLOWING POINTS:

- WE OPERATE A SAFE, EFFICIENT, COST EFFECTIVE SYSTEM AND WILL CONTINUE TO STRIVE TO IMPROVE IT.

- WE ARE OPTIMISTIC ABOUT THE FUTURE OF PIPELINING AS A MAJOR MODE OF TRANSPORTATION FOR NATURAL RESOURCES.

- THERE WILL BE A CHALLENGES BUT ALSO OPPORTUNITIES.
- DUE TO THE PACE AND MAGNITUDE OF CHANGE, PARTICULARLY DURING THE NEXT 3 - 5 YEARS, IT IS IMPORTANT THAT ALL SEGMENTS OF THE OIL AND GAS INDUSTRY WORK TOGETHER AND COMMUNICATE THEIR PLANS AND INTENTIONS EFFECTIVELY.

LET'S WORK TOGETHER TO MEET THE CHALLENGES OF CHANGE!

THANK YOU FOR YOUR INTEREST AND ATTENTION.

WORLD CRUDE OIL PRICE SCENARIOS

WEST TEXAS INTERMEDIATE AT CHICAGO
(1986 U.S. DOLLARS PER BARREL)

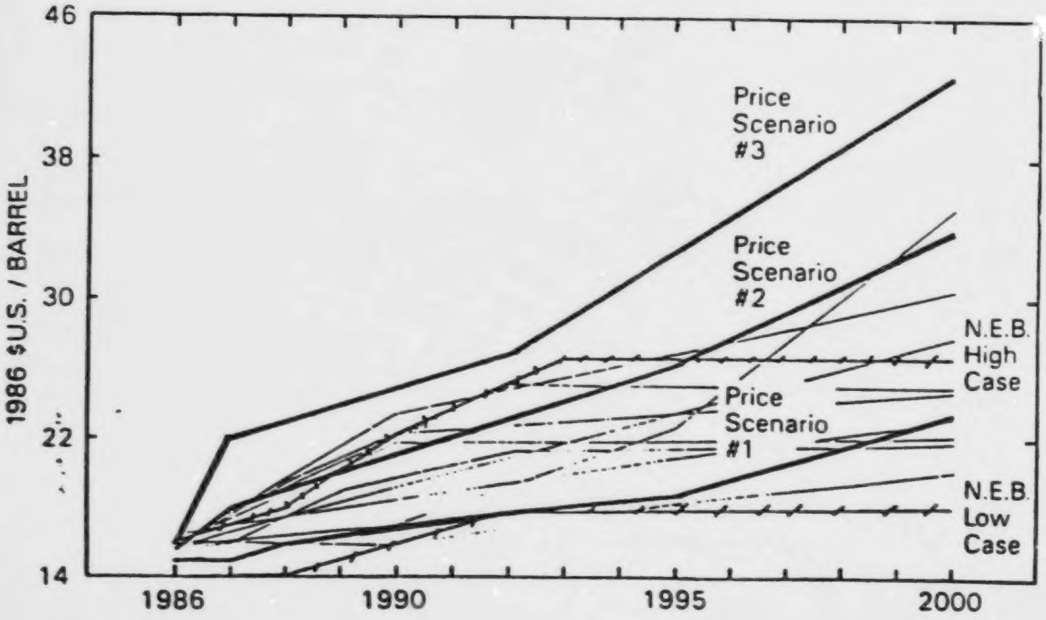
SLIDE 1

	Scenario 1	Scenario 2	Scenario 3
1986	15	15	15
1987	15	18	22
1988	16	19	23
1990	17	21	25
1992	18	23	27
1995	19	26	33
2000	24	34	43

WORLD CRUDE PRICE FORECASTS

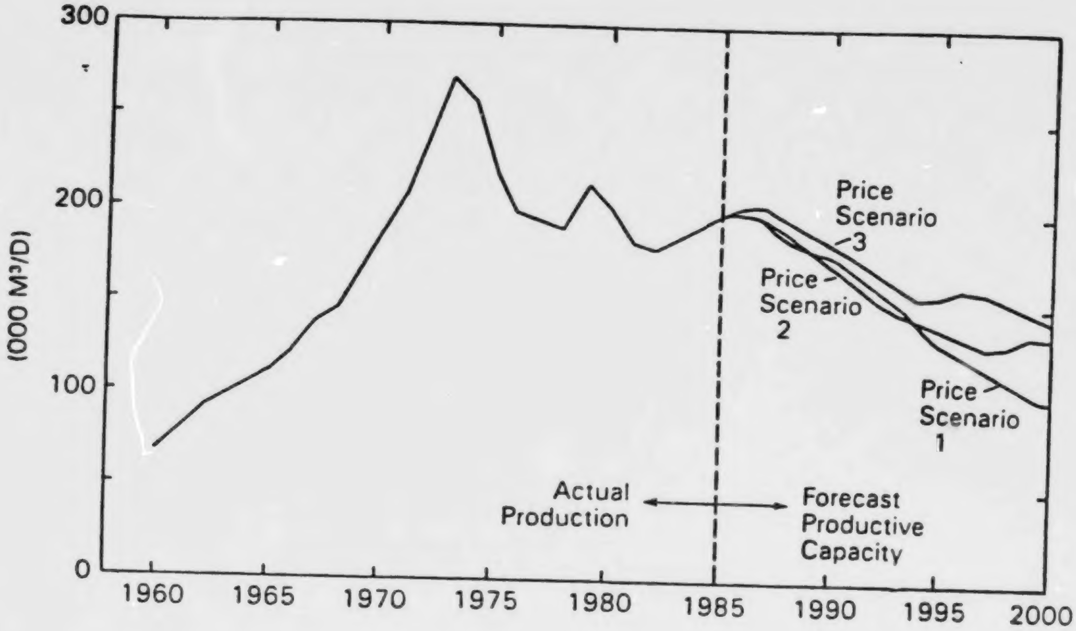
WEST TEXAS INTERMEDIATE AT CHICAGO

SLIDE 2



SUPPLY OF LIGHT CRUDE OIL AND EQUIVALENT

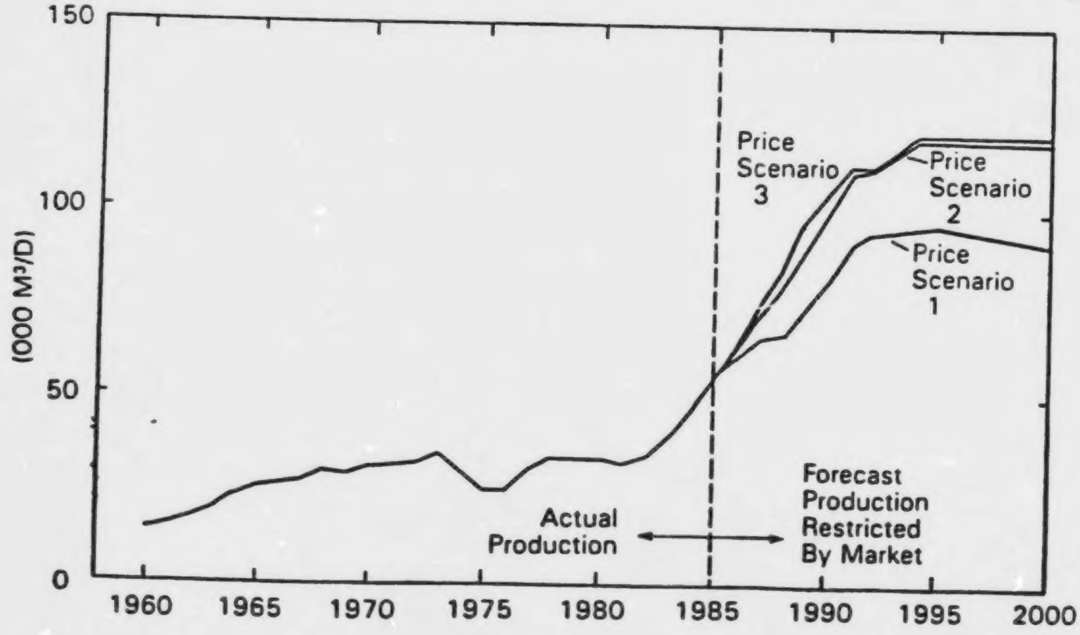
SLIDE 3



SUPPLY OF HEAVY CRUDE OIL AND BITUMEN

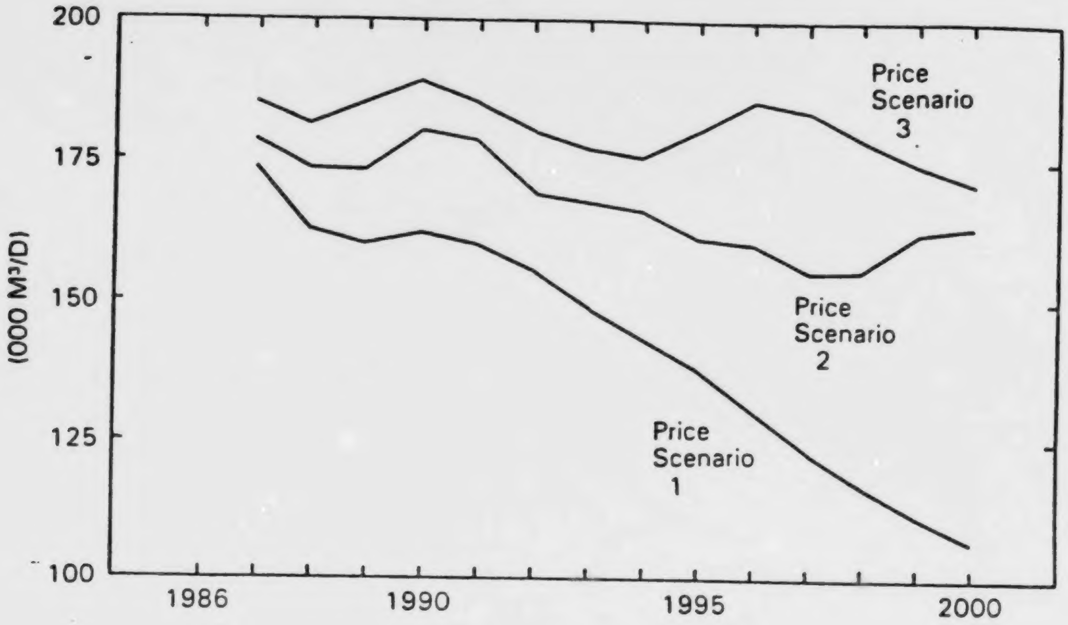
(BLENDED)

SLIDE 4



FORECAST NET WESTERN CANADIAN CRUDE OIL PRODUCTION AVAILABLE TO IPL

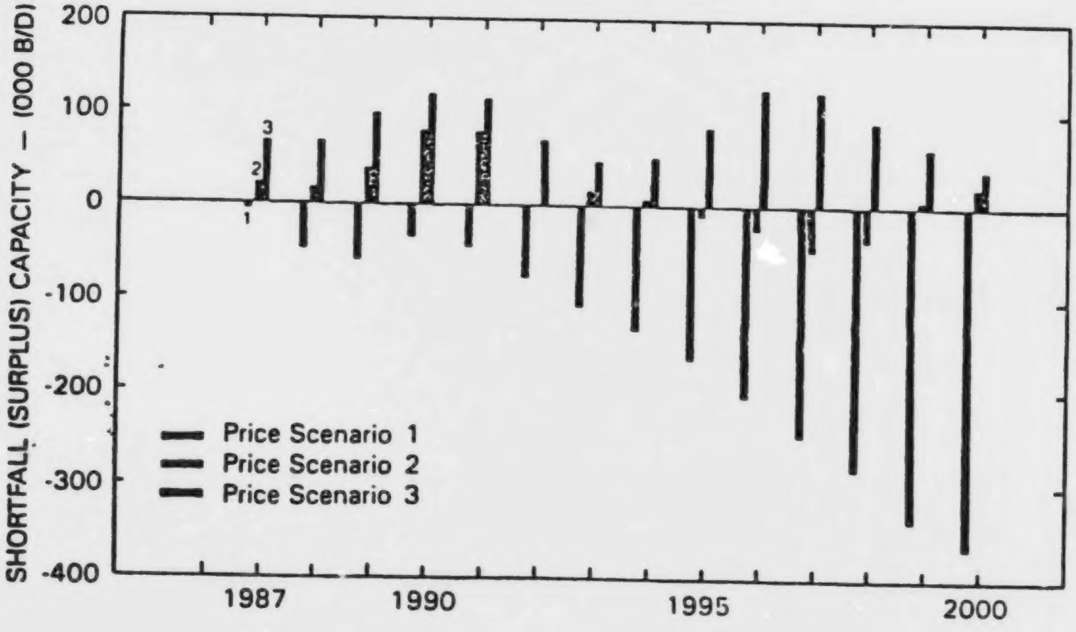
SLIDE 5



CAPACITY SHORTFALL AFTER PHASE III COMPLETED

EX KERROBERT

SLIDE 6



FORECAST OF BITUMEN AND HEAVY CRUDE OIL PRODUCTION — UNDILUTED

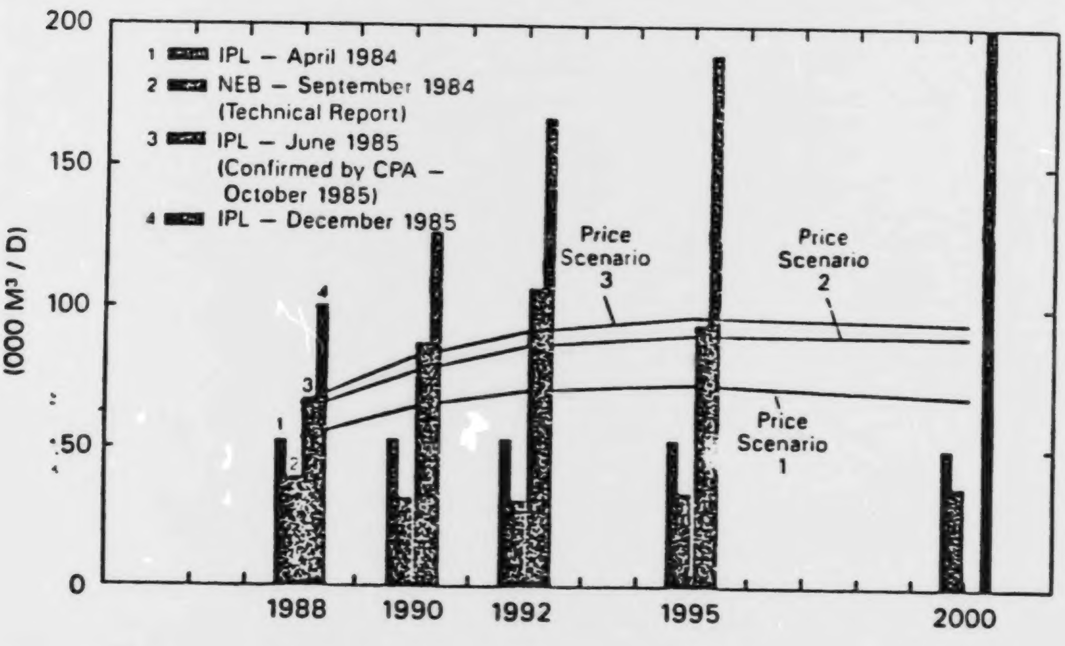
(ALL VOLUMES IN 10^3M^3 / D)

SLIDE 7

Line No.		YEARS				
		1988	1990	1992	1995	2000
1	IPL — April 1984	54.1	54.4	54.9	54.7	50.7
2	NEB — September 1984 Technical Report	40.1	30.4	32.3	35.1	38.6
3	IPL — June 1985 (Confirmed By CPA — October 1985)	68.3	88.0	107.1	94.8	
4	IPL — December 1985	100.3	128.3	168.5	190.4	201.9
	CPA / IPAC — May 1986					
5	Price Scenario 1	54.4	65.9	73.2	73.5	69.2
6	Price Scenario 2	62.6	78.8	87.5	91.4	91.5
7	Price Scenario 3	65.4	82.9	93.2	97.8	96.2

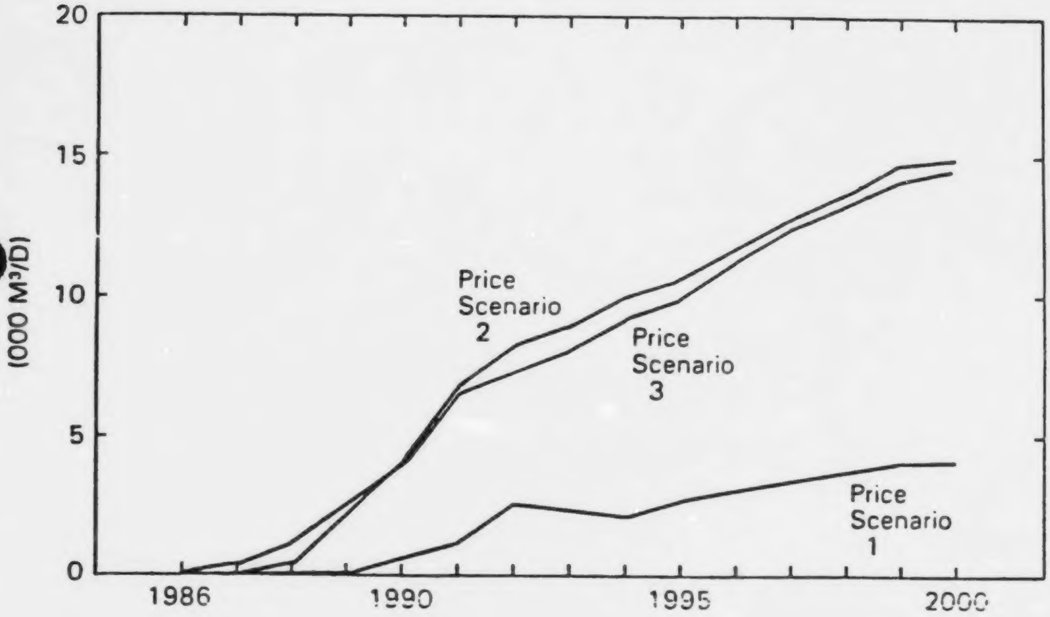
FORECAST OF BITUMEN AND HEAVY CRUDE OIL PRODUCTION — UNDILUTED

SLIDE 8



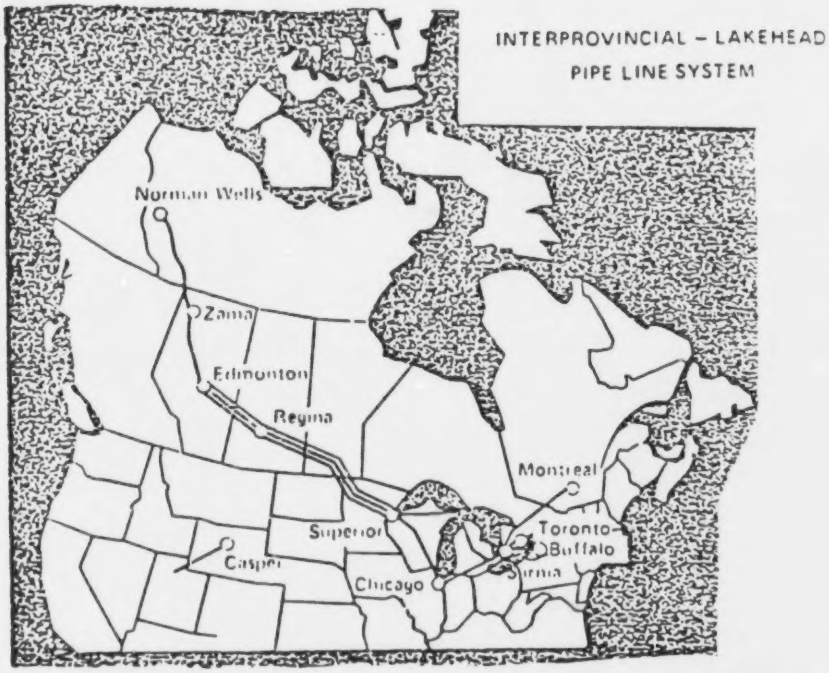
FORECAST CONDENSATE SHORTFALL FOR DILUENT PURPOSES

SLIDE 9



MARKETS FOR WESTERN CANADIAN HEAVY CRUDE OIL AND BITUMEN (1993)

	VOLUME (1,000 B/D)
CANADA	
WESTERN CANADA	30
EASTERN CANADA	55
UPGRADERS	160
CANADA SUBTOTAL	245
UNITED STATES	
EXISTING MARKETS	
IPL SERVED	400
RANGELAND SERVED	30
TRANS MOUNTAIN SERVED	0
	430
POTENTIAL FOR MARKET DEVELOPMENT	
CHICAGO SOUTH	120
EAST/GULF COASTS	30
	150
U.S. SUBTOTAL	580
TOTAL POTENTIAL MARKETS	825
ASSUMED MARKET PENETRATION	755
PRODUCTIVE CAPACITY (PRICE SCENARIO 2)	775


INTERPROVINCIAL – LAKEHEAD
PIPE LINE SYSTEM

Norman Wells
Zama
Edmonton
Regina
Montreal
Superior
Toronto
Buffalo
Casper
Chicago
Sarnia

MANAGING RISK

IN A NEW ERA OF OIL PRICE VOLATILITY

A Presentation by Jan Kay

Vice President of Marketing

The New York Mercantile Exchange

Delivered before

The International Oil and Gas Markets Conference

Calgary Convention Center

Calgary, Alberta

September 16, 1986

I'd like to start by thanking the Canadian Research Energy Institute for allowing the New York Mercantile Exchange the opportunity to be represented at this impressive and important gathering. I view this invitation as reflective of two developments in the oil industry. The industry's growing need to protect itself against price volatility and its increasing use of futures markets in accomplishing this task.

In the past, oil pricing was a simple business. At one time, it has been said, the price of oil was dictated by a single individual. Then, for the better part of this century, pricing was controlled by groups of people that could be comfortably accommodated in a small sitting room.

Today, no single individual, nor group of people has the economic clout to control the oil market. As a result, no longer can anyone be certain what oil prices will be tomorrow, let alone next year.

At a time when oil prices can rise or fall by as much as 50 percent over the course of days, if not hours, even the most efficient of companies cannot avoid losses without the use of sophisticated risk management strategies. And that is what I'm here to talk about today -- managing risk through the use of futures markets. I am going to discuss how futures markets can be utilized by the oil industry for hedging, marketing and price discovery. I am also going to tell you a bit of what is going on at NYMEX these days.

But, I'm going to start by explaining, in a philosophical fashion, what NYMEX is and what it is not. NYMEX doesn't buy or sell oil. Nor does it take a profit or loss from changes in the price of oil. And most of those who trade on the floor of the Exchange would not claim exceptional expertise regarding the oil industry.

Actually, from your point of view, NYMEX's most important role is to provide innovative risk management tools and a forum where they may be traded.

It is on the NYMEX trading floor that representatives of all parties involved in the trading of oil meet. In the course of this very noisy, competitive and public encounter, the value of crude and other oil products are determined and revised every few seconds. When the price of oil changes on NYMEX, it is not NYMEX that is changing it, nor the floor traders on NYMEX.

Rather, it is the ebb and flow of orders into the ring that determines the price. This order flow represents the collective opinion of the world's supply and demand for oil, combined with the unpredictable impact of economic and political events, all being reacted to by consumers, suppliers, traders and investors from around the world.

Whether this is better or worse than the closed system that once existed is not for me to say. Clearly, it is quite different. But increased price volatility requires a company to examine sophisticated risk management systems. Which brings us to the subject of hedging on futures markets.

Hedging

Let me start by explaining what I mean by hedging. Just as an individual hedges against the possibility of serious illness or untimely death by buying medical and life insurance, a business can hedge against the possibility of "life threatening" shifts in the value of materials they either produce or consume by buying "price insurance" in the form of futures or options contracts.

Today I will concentrate on futures. These contracts call for the delivery of a specifc amount of a specified grade of a given commodity, to be delivered at a specified location within a given time frame. In the case of NYMEX crude oil futures, the amount is 1,000 barrels, the grade is West Texas Intermediate, the delivery location is Cushing, Oklahoma and the time frame is any listed trading month. The only negotiable aspect of this contract is its price.

Properly used, these contracts allow a company to lock in a price they will either receive or pay for a given product.

As with any form of insurance, you give up something to get something. In the case of futures contracts, you give up the opportunity of unanticipated gains as the cost of insuring against unanticipated losses. In the case of options, unanticipated losses are avoided by the payment of a premium, while the ability to capitalize on unanticipated gains is retained.

The need to hedge is a function of price volatility. Without volatility, and sufficient prices, a high success rate in finding petroleum reserves is sufficient to result in profitability for a well run company in the upstream. Running an efficient high-yield refinery will do the same in the downstream. With volatility, an unanticipated drop in prices will jeopardize both the producer's and refiner's profitability. On the consumer side, a rise in oil prices can mean the difference between a profit and loss for trucking firms, airlines, utilities, and so on. With price volatility, corporate planning can be a very "iffy" proposition.

Over the past year, oil has become among the world's most volatile commodities. Bear in mind, it is not only the rise or fall of prices that make for volatility, but also the speed with which such movements occur. Between November of last year and April of this year, the NYMEX spot price for WTI crude tumbled from nearly 32 dollars a barrel to under 10 dollars.

Over shorter periods of time, the price moves have been even more dramatic. In April alone, spot crude traded in a range of between 10 dollars and 14 dollars and 40 cents. That is nearly a fifty percent trading range. And single day trading ranges have been almost as dramatic. Few market traded products have been as volatile over the past year. Not gold, not treasury bonds, not even the S&P stock index.

In today's competitive oil markets, spot prices have become the "shock absorbers" which balance supply and demand. Like the price of financial assets, oil prices react quickly, and often violently to news.

OPEC appears to be reaching an agreement on production quotas. The price goes up. A meeting of oil ministers ends an hour before it is scheduled to conclude. Prices go down. George Bush speaks in Texas and expresses concern regarding the State's economic plight. Prices go back up again.

It is just these conditions that have subjected unhedged oil-related companies to traumatic shocks over the past year. On the other hand, businesses that have attempted to manage their exposure have enjoyed greater financial stability.

Companies have, thus far, been employing several different methods, other than futures contracts, for managing their risk.

- Refiners have, to an extent, shifted price risk to producers with netback deals. This has left many producers vulnerable to price shifts and reactive competitive practices.
- A number of larger companies have used the informal and unregulated Brent forward market. At least they did until a series of defaults took place this past February.

- Finally, a number of producing nations have attempted to limit their risk by integrating downstream. This would appear to be an approach with limited applications.

For most of you in the room today, the only consistently available and secure avenue for price hedging will be the futures and options marketplace. Commercial oil hedgers of all sizes and from all segments of the industry have begun to utilize futures contracts with increasing regularity.

There are a number of reasons for this. First of all, futures trading, while public, permits a company to take market positions with anonymity. Standardized contracts and regulations pertaining to margins and position limits protect participants. Futures contracts permit a company to implement a versatile trading strategy that can be constantly modified based on changing market conditions. Their applications are as numerous as the commercial activities of the oil industry itself.

There is one important thing to remember in trading futures contracts. While delivery of oil can be and often is made or taken on such a contract, this does not have to be the case. Normally, the market is used as a financial tool. The vast majority of participants use the futures market as a proxy for the physical market and close out their positions before a contract is due for delivery. They then go into the physical market to conduct their physical transactions.

In a well publicized example of how the market is used to hedge, last fall Mesa Petroleum presold its entire 1986 crude production of four million barrels on NYMEX. This short, or selling hedge, locked in a price of 26 dollars and fifty cents per barrel. I'll leave it to you to tally up the total losses they avoided through this hedge.

Independent oil producers in Canada have come to recognize the quantifiable relationships that exist between the prices of various types and grades of oil. Many now sell NYMEX WTI futures to establish effective prices for their own output.

Similarly, cash market traders importing cargos of foreign crude, such as North Sea Brent, to North America also use short hedges to protect the value of the inventory in transit.

These examples illustrate that, although a futures contract might specify delivery of WTI in Oklahoma, cash market deals involving delivery of non-WTI crude at other locations, can and are being hedged with a standard contract. As I've mentioned, the key reason why one can hedge with WTI, regardless of the specific oil being sold or purchased, is that WTI prices move in conjunction with other world prices. NYMEX has already statistically demonstrated this for Atlantic Basin light sweet crudes such as Brent, and for heavier sour crudes such as Atlantic North Slope.

For every seller there is usually a buyer and for every short hedge, there is also a long or buying hedge. A petrochemical company in Canada has used this mechanism to fix its feedstock costs.

In addition, U.S. refiners routinely buy crude oil futures and simultaneously sell heating oil and gasoline futures to lock in refinery margins. Such transactions are called "crack spreads".

Refined product marketers, who buy products at flexible prices and have fixed-price sales contracts, are also natural long hedgers, as are the end-users of the refined products. Since diesel and jet fuel prices are related to NYMEX heating oil futures prices, these end users, or long hedgers, include airline companies, bus companies and public transit operators.

In what may be the newest development in hedging, governments are looking at the use of futures to hedge. For example, a bill was introduced into Louisiana's State Legislature which would permit the state government to trade futures. According to published reports, national oil companies, such as Statoil of Norway, are already trading futures.

Marketing

Hedging is not the only use that companies can make of futures markets. Futures contracts can also be used by companies as marketing and sales tools. For example, a futures position that culminates in delivery guarantees not only a price, but also a customer. Last year, 159 million barrels of crude oil were delivered via NYMEX contracts. This year the total is likely to exceed 250 million barrels, representing nearly 10 percent of U.S. oil production. And this still only represents a small fraction of the total amount of oil that is trading on NYMEX annually.

The two parties to any oil futures contract delivery can be matched randomly by the NYMEX Clearing Department in standard or alternate delivery procedures. But many companies find these procedures to be somewhat rigid. The grade may not be appropriate, or the delivery location may be inconvenient for many.

As a result, many participants use a procedure known as an Exchange of Futures for Physical, or EFP. An EFP, in essence, permits anyone wishing to make or take delivery to find his or her own partner. Under this system, every aspect of the delivery becomes negotiable -- location, grade, timing, method of payment and so on. Canadian firms often use this technique. Much more oil is delivered each month via EFPs than is delivered via regular Exchange delivery procedures.

EFPs can be effected for Canadian exports, for domestic sales, and for imports into eastern Canada.

Consider a Canadian exporter with a short futures position. The company can exchange futures with a refiner in the U.S. who is long in the futures market and, thus, effect an EFP delivery. Timing of delivery is flexible and may depend on capacity constraints of the Interprovincial Pipeline System. Pricing is usually at a discount to WTI, with the differential being determined by transportation cost, quality and scheduling.

As this example suggests, EFPs represent the most flexible delivery procedure for many market participants.

Pricing

Futures markets serve one other important function for industry -- price discovery and dissemination. This is important, because even those companies which do not use the market often still use futures prices to set their own prices. In more established markets, such as industrial metals, producer prices have long been linked directly to futures prices.

This is now becoming the case with oil as well. Inflexible and administered prices are going by the wayside. Over the past year, the vast majority of traded oil has flowed under netback, spot or other market-related prices. In North America, an ever growing group of oil companies use futures prices in devising pricing formulas for the purchase and sale of crude oil and in determining domestic postings.

Postings are now subject to numerous monthly changes. This is in marked contrast to a few years ago when they were altered once every few months.

The reason for this new found flexibility is obvious. If a company's prices are not competitive, its market share will be in jeopardy. This has been true for countries as well as companies.

In a recent report on futures, the Independent Petroleum Association of America stated: "If trading on the crude oil futures market continues to increase and gain more acceptance, futures prices could eventually replace refiners postings."

One reason for the increased importance of futures market prices, is the nature of the futures market itself. It is, as I suggested earlier, a public forum where all parties have access to the market. A mix of industry participants, including local floor traders and outside speculators, give the market great breadth of opinion and constant liquidity.

It is this liquidity that allows even the largest market participants to enter and exit the market with ease and without having a dramatic impact on the price of a product.

In the cash market, where there is neither regulatory oversight nor public reporting requirements, price quotes differ widely amongst sellers. In contrast, prices on futures markets are fully transparent. They are determined continuously by open outcry trading and are instantaneously sent around the world by a sophisticated data distribution system. At the end of each day, they are reported throughout the media.

Through this system of price dissemination, all market participants are placed on an equal footing.

NYMEX - The Energy Exchange

While I have been speaking of futures markets and futures trading in a somewhat generic fashion, most of what I have said relates directly to my exchange. Before I close, I'd like to spend a few more minutes discussing how NYMEX became involved with the oil industry, where it stands today, and what the outlook for it is.

NYMEX introduced its first energy contracts -- for heating oil and residual fuel with Rotterdam delivery -- in 1974. They quickly failed. This was primarily because a necessary ingredient for a successful futures contract was lacking at the time -- a competitive and open cash market. By the late 1970s, however, with the deregulation of domestic prices in the United States and a more competitive world industry, the stage was set for futures trading. Thus, in 1978 NYMEX successfully introduced a heating oil contract with New York Harbor delivery.

In 1981, NYMEX introduced a second successful contract with New York delivery -- futures on leaded gasoline. This was later followed with an unleaded gasoline contract which is slated to totally replace the leaded contract this coming November.

NYMEX's flagship contact, crude oil futures, began trading in 1983. Over the past three years, it has not only become NYMEX's most actively traded contract, but the fastest growing futures contract, of any sort, in the world.

In 1985, crude oil futures volumes grew by 116 percent to reach 3.98 million contracts, the equivalent of nearly 4 billion barrels of oil. During the first eight months of this year alone, the equivalent of more than 5 billion barrels were traded in the crude oil ring. Open interest -- the inventory of open futures positions -- reached 135,000 contracts in July. Only two other futures contracts have larger open interest.

Another barometer of growth at any exchange is seat prices. In the late 1970s, prior to the introduction of our energy contracts, the price of a NYMEX seat was less than 5,000 dollars. Recently a seat sold for 165,000 dollars.

And the potential for even greater growth in oil trading exists. After all, the 135 million barrels of oil currently represented by the contract's open interest accounts for less than one percent of the world's annual oil production.

Both growth and heightened risk in the energy markets, over the past year, have led NYMEX to take steps to tighten its regulatory procedures and enhance the financial integrity of the market place. These steps have included:

- Increased trading margins for all energy contracts;
- Increased financial requirements for leaded gasoline deliveries; and
- A doubling of the size of contributions by clearing firms to the Exchange's Guarantee Fund.

Over the years, NYMEX has worked hard to develop useful risk management vehicles for the energy industry. This effort extended beyond our staff and members and has included the input of many representatives of the oil industry, including some who are here today.

Based upon their combined efforts, NYMEX will be introducing another energy-related product this fall -- options on crude oil futures. Needless to say, options can and will be the sole subject of a separate speech. Let it suffice to say that these instruments will provide a whole new range of opportunities for commercial hedgers, giving them a number of limited-risk alternatives to futures trading.

NYMEX is also planning to introduce both natural gas futures and heating oil options during the coming year. In addition, the Exchange has formed a Propane Advisory Committee to examine the possibility of trading propane gas futures.

With these new contracts, we hope that NYMEX will be able to serve an even broader range of energy industry constituents.

Conclusion

In a very brief period of time, the world of energy trading has been dramatically altered. In little more than a decade, the control of pricing has shifted from the seven sisters, to OPEC, to no one or everyone, depending on your point of view. And the pace of change has quickened.

If what has been true for other commodities holds true for oil, it is unlikely that the price of oil will ever again be controlled by any one group. If that be the case, I think that many of you here today will become ever more familiar with NYMEX in the years to come.

International Oil and Gas Markets Conference

Sponsored by

Canadian Energy Research Institute

and

Calgary Chamber of Commerce

"Developments in the Refining Industry"

R. G. Bruce

North American Refining

Conoco Inc.

September 16, 1986

Developments in the Refining Industry

You have heard about world oil/supply demand, prices and politics; about the Pacific Rim, Canadian gas and heavy oils. And, you have just heard from the pipeliners and the future traders.

Slide 1

This has been a broad range of subjects and I will be following that same pattern within my assigned area as I cover some facts, some forecast and even some philosophy.

I have been asked to talk about Refining developments -- I assume that means not just the past, but things that will happen in the future, and I doubt any of us are very comfortable with that subject.

Turbulent political and economic events in recent years reenforce our instinctive feeling that the future is inherently unpredictable. But, we continue to try for some perception of the future because it seems necessary for rational, intelligent decision making.

So, first some background --

Let's look at a few changes that have taken place just in this decade, since 1980 --

Slide 2

U.S. price controls were on in 1980 — West Texas Intermediate crude was priced at $6.70 — yes it was, Lower Tier price controlled oil was $6.70, Upper Tier $14.50 and Stripper Oil about $31.00. WTI has since gone to over $35 and now back to $10 or $12.

Slide 3

Arabian Light really hasn't been much different with a high near $35 and a current spot value of about $10 to $12.

This has been super traumatic for both explorers and producers but, frankly, for refiners and marketers the last couple of years have not been too bad. But -- it did require certain actions to obtain positive results.

Slide 4

Some key petroleum demand moves since 1980 are:

- o U.S. Gasoline - down - 500 thousand barrels per day
- o U.S. Resid - down - 1.6 million barrels per day
- o U.S. Total Oil - down - 2.8 million barrels per day

Slide 5

and, on a more broad world wide look

- Resid - down - 5 million barrels per day
- Total Oil - down - 7 million barrels per day

And, here are some of the actions or maybe they were reactions, that have been taken:

Slide 6

While the Mid-East and North Africa did add 1.4 million barrels of refining capacity, U.S., Europe and Japan reduced their capability by almost 9 million.

Slide 7

A closer look at the U.S. shows that since 1980, the number of operable refineries has gone down more than 100 from 319 to 216. That's what we keep calling Rationalization. Dictionary definition: "To free from irrational parts". I guess that is what we have been doing; over 100 "irrational parts".

Slide 8

And, along with this, operable capacity has been reduced by over 3 million barrels per day from a high of almost 19 to today's 15.4 million.

Slide 9

And here is the result; bars show demand and the line indicates capacity. We see shortage -- excess -- and finally near balance. Realize, though, this is just distillation capacity and may not be attainable as increased gasoline quality is demanded. So, our "balance" could be a bit short.

But the result . . . . a very painful but necessary industry rationalization seems to have attained its goal. U.S. demand and processing capabilities are closely matched and should support a continuing strong refining industry profit making capability.

This is not to say plant closures, mergers and consolidations are all over. Weak operators will continue to be eliminated and strong ones will expand. But, I do believe the wholesale closure and retrenchment phase is about to abate and that capacity is at a sustainable level.

-- That's mostly history. Let's talk about some upcoming trends.

Slide 10

I will spend a few minutes on each of these:

- Crude Oil quality and value

- Product qualities
- Productivity
- Other factors
- Philosophy change?

Slide 11

Let's think a minute.

What really determines the value of a crude oil?

1. What it's made of (composition)
2. Where it is (location) — Both of these factors are of particular interest to producers of Heavy - Sour - Remote crudes.

First, composition . . .

A forecast of the two most important crude characteristics, sulfur and gravity, indicates that while the absolute value changes are not large, the changes and direction of change are significant.

Slide 12

The average percent sulfur in crude will increase from today's value of just over 1.15% to a 1995 level of perhaps 1.3% (that is over a 10% increase -- on the entire crude pool).

Slide 13

While the gravity drop is going from 32.25 to 32.0 — which is, again, a significant move when applied to the total pool. . .

So, the trend is heavier, more sour, poorer quality crude.

Slide 14

What's it's value to be —

That must be heavily weighted by the cost of getting it to a refinery that can process it. Heavy Oil competition is Canada, Venezuela, Mexico, California and Wyoming. Processing capacity is available primarily on the U.S. Gulf Coast with some in California and in the Chicago area.

Both California and your Canadian crudes will have to be priced to reach refining centers competitively and probably to repay certain transportation facilities construction.

Slide 15

Next Trend - Product Qualities

Slide 16

Our U.S. industry has three upcoming challenges:

1. With lead removal, gasoline octane will be an ongoing challenge. I foresee increased processing severities along with use of MTBE and other oxygenated components and additional isomerization processes.
2. Second, Governmental actions will likely reduce gasoline vapor pressure limits. This is expensive. Butane will be displaced — to some other use -- and that volume must be replaced by a low vapor pressure, high octane component.
3. And talk abounds that the sulfur level in diesel fuel may be reduced to 0.05% or less -- that too, would be very expensive calling for much increased hydrotreating and segregation of stocks.

Slide 17

Industry Productivity

Slide 18

The industry will not be looking at expansions to increase profitability so it must look to efficiency. It will be looking at maintenance and modification, not grass root construction. And, three factors will determine its relative success:

1. Safety -- a super expensive item, if ignored. It requires maximum overt attention at all times.
2. Technology — computers, planning, purchasing, materials control -- acceptance of new ways --
3. Employee Motivation -- monetary incentives, awards, recognition -- whatever it takes to stimulate performance.

Let me expand on this one with a more specific example. Our parent company, Du Pont, has become an enthusiastic implementor of a concept called Organizational Effectiveness. And, we at Conoco are beginning to see why!

Slide 19

Without a full-blown presentation I will summarize it as a means of more fully utilizing the individual abilities of people at all levels of an organization — bottom to top.

This is done to attain commonly developed and accepted goals.

It is a revised means of management. In fact it is said to be a Revised Organization Culture.

We believe it is -- it must be — a future trend.

Slide 20

What else?

Slide 21

Just a list, without much comment:

1. New Environmental Requirement -- I don't even know what, I just know that over the next several years, We will be spending a lot of money to make the air, water and land cleaner.

2. Netback Crude Pricing -- a new way of doing business -- does it give us the right incentives?

3. Crude/Product Paper Markets -- are the futures markets a profit opportunity or a threat to stable business?

4. OPEC - simply stated, the major world oil reserves have not moved.

Slide 22

One more . . .

Philosophy change - with question marks?

Slide 23

Past industry integrated operations have generally pointed toward making money by producing oil (Upstream). Then, moving that oil to user markets as inexpensively as possible while, hopefully, recovering cost (that was Downstream).

What is changing that?

- Producer country economics
- Fewer balanced, integrated companies
- In the US; being a net importer.

Slide 24

As Upstream finds it more and more difficult to make money, Downstream is changing . . .

- Showing restraint in product output
- Insisting on a reasonable price margin
- Simply not buying expensive or overpriced crudes
- Making money

We are seeing, and I think will continue to see, more balance -- both Upstream and Downstream must be healthy and financially sound.

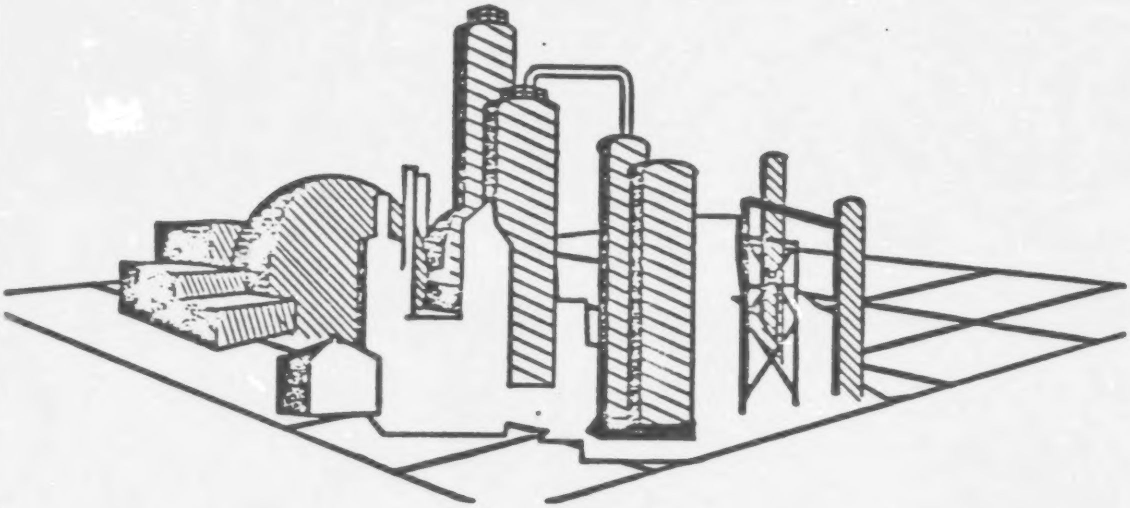
Slide 25

My summary

1. U.S. and maybe even free world refining industry has brought itself into acceptable capacity balance.
2. Certain challenges remain -- crude quality, product specs, and especially productivity.
3. But we are ready — a healthy industry postured to prosper.

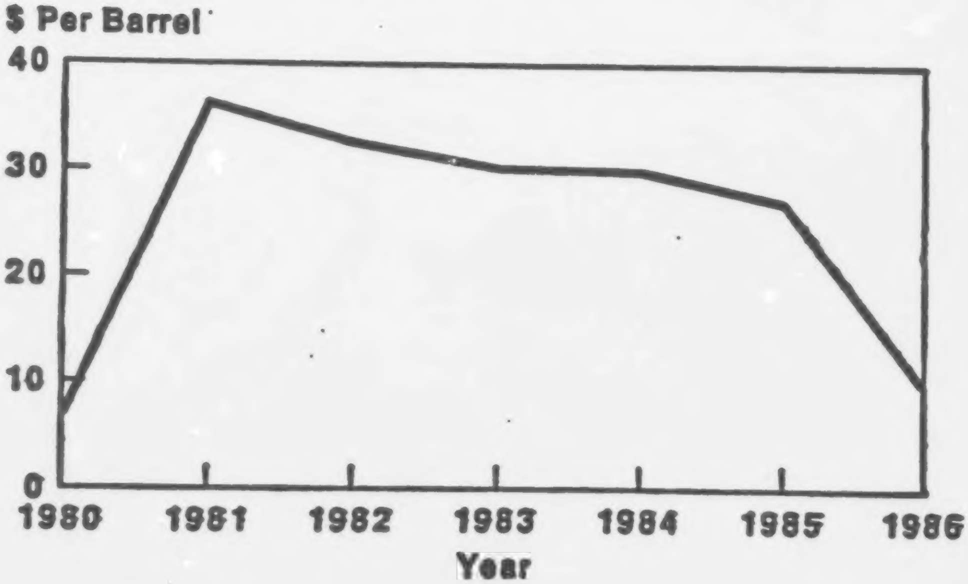
/jk
9/5/86
RGB6:054

DEVELOPMENTS IN THE REFINING INDUSTRY



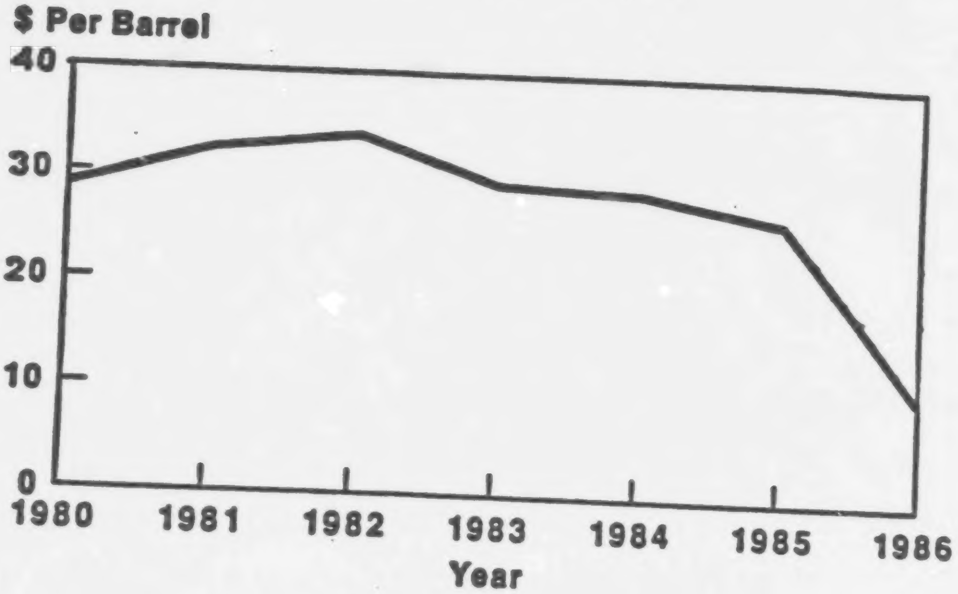
Slide 1

WEST TEXAS INTERMEDIATE



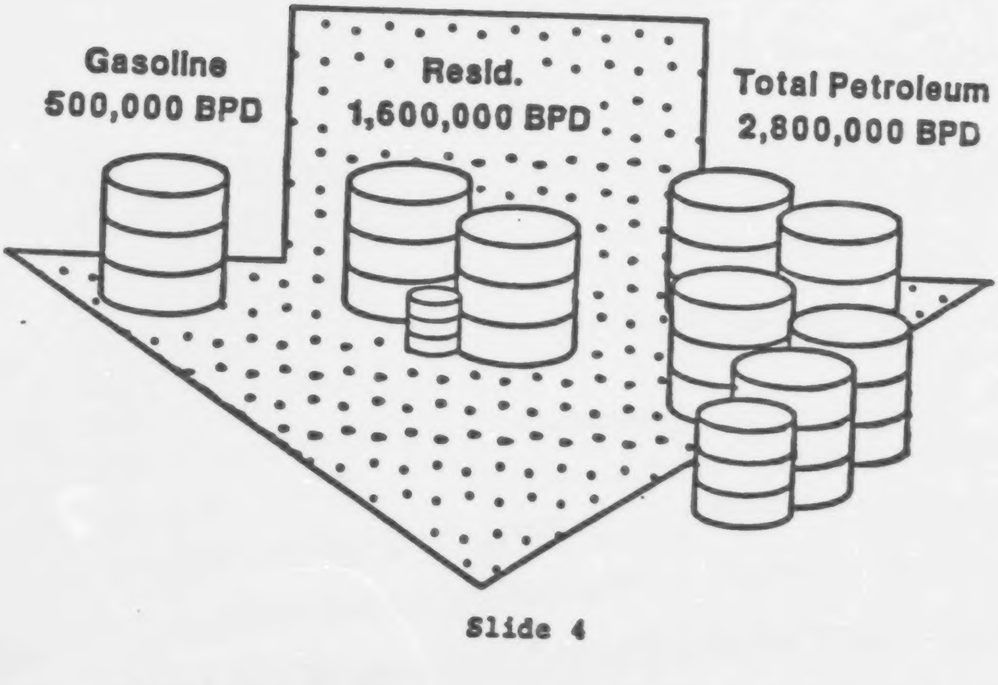
Slide 2

ARABIAN LIGHT



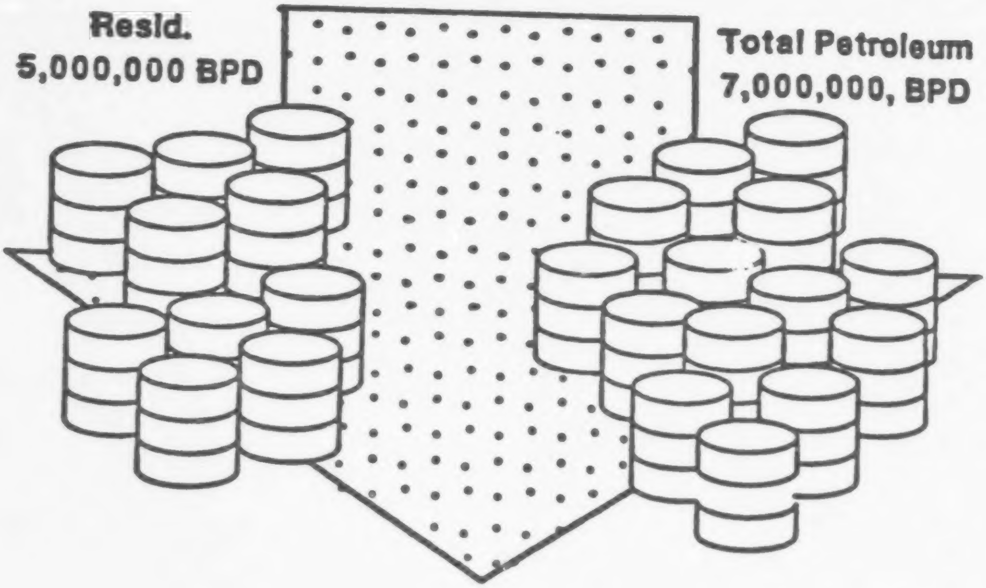
Slide 3

1980's PETROLEUM DEMAND UNITED STATES


Gasoline
500,000 BPD
Resid.
1,600,000 BPD
Total Petroleum
2,800,000 BPD

Slide 4

1980's PETROLEUM DEMAND FREE WORLD

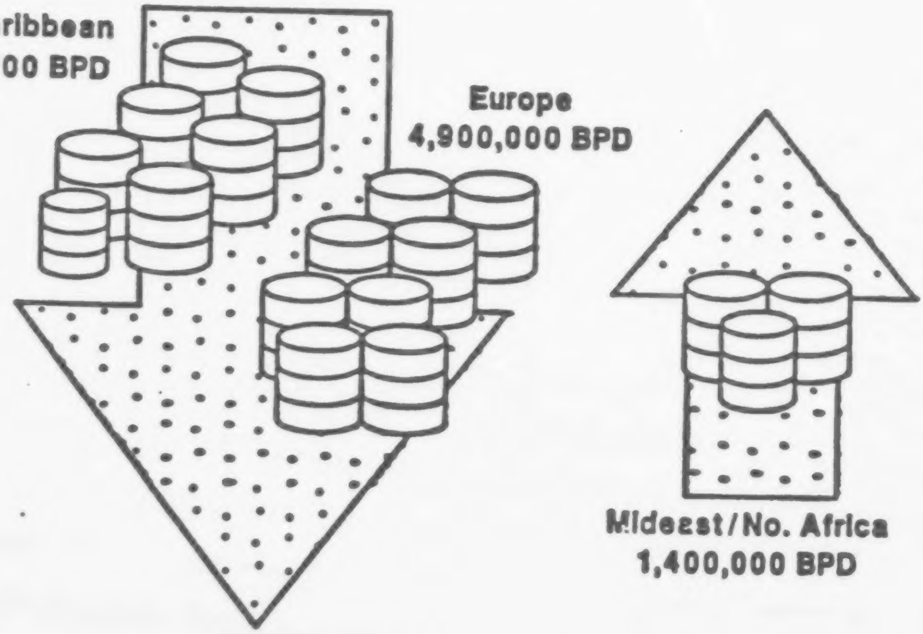


Resid.
5,000,000 BPD

Total Petroleum
7,000,000, BPD

Slide 5

REFINING CAPABILITIES



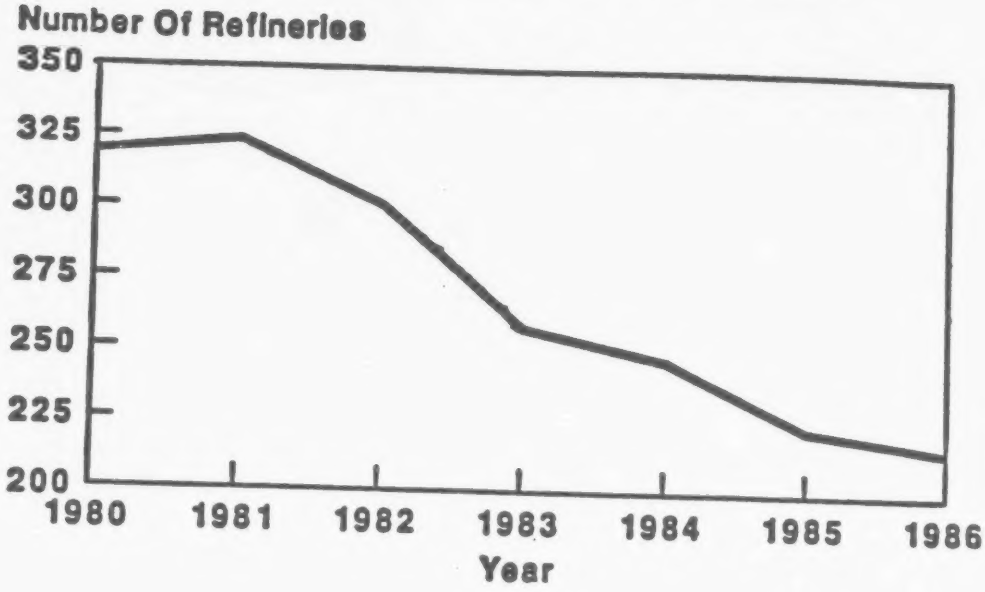
U.S./Caribbean
3,300,000 BPD

Europe
4,900,000 BPD

Mideast/No. Africa
1,400,000 BPD

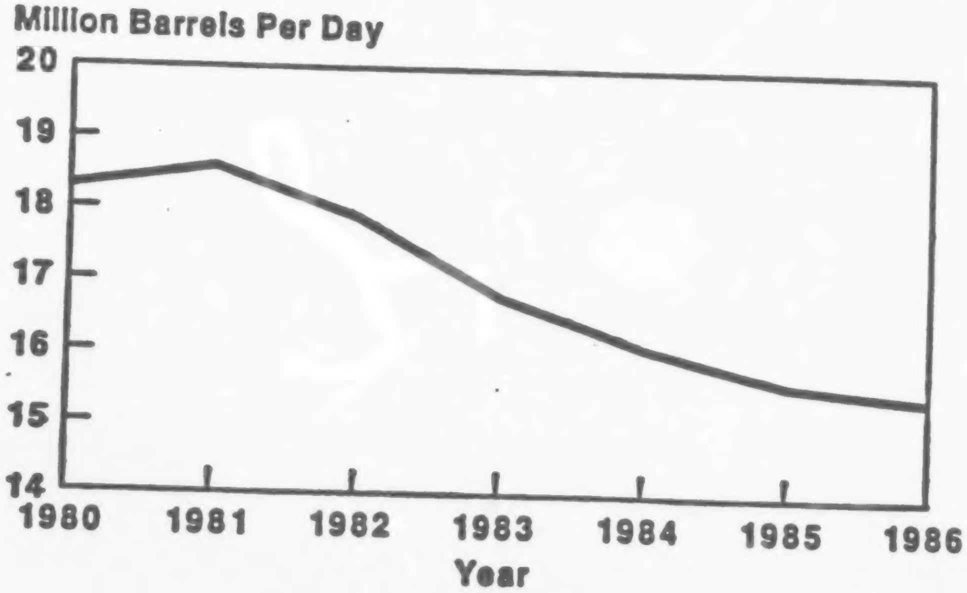
Slide 6

OPERABLE U.S. REFINERIES



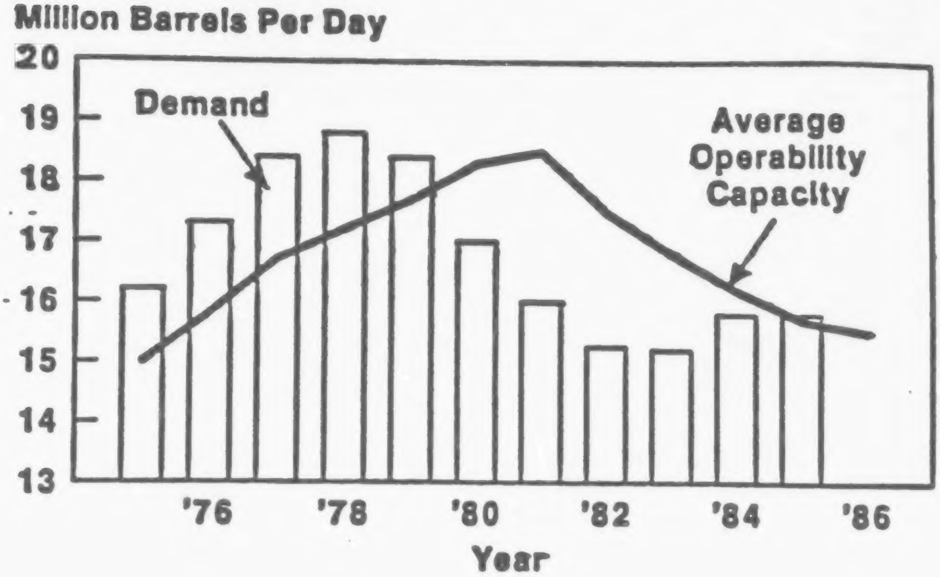
Slide 7

U.S. OPERABLE REFINING CAPACITY



Slide 8

U.S. PETROLEUM DEMAND AND DISTILLATION CAPACITY



Slide 9

REFINING TRENDS

- Crude Quality/Value
- Product Qualities
- Industry Productivity
- Other Elements
- Philosophy Change?

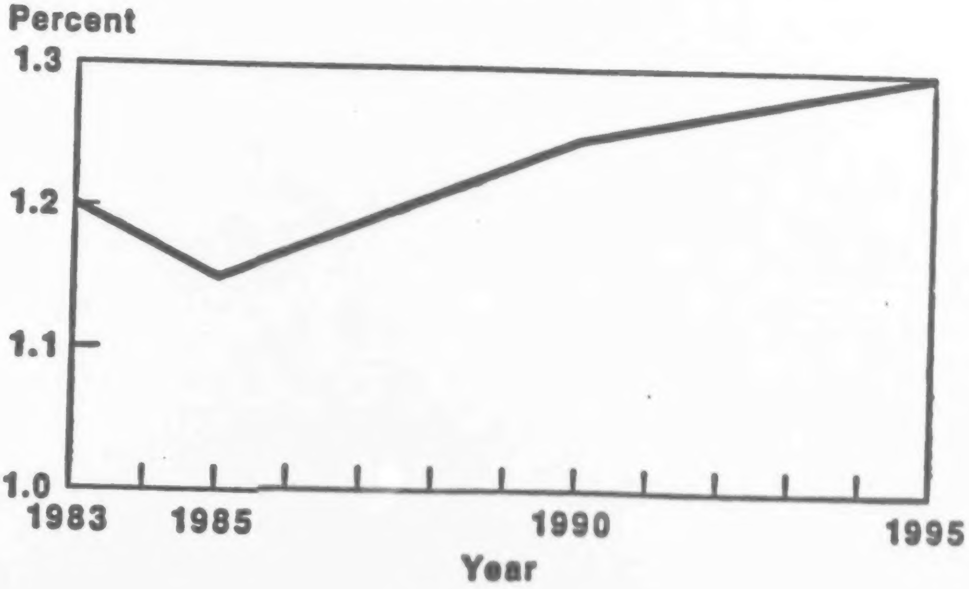
Slide 10, 15, 17, 20, 22

CRUDE OIL VALUE

- Composition
- Location

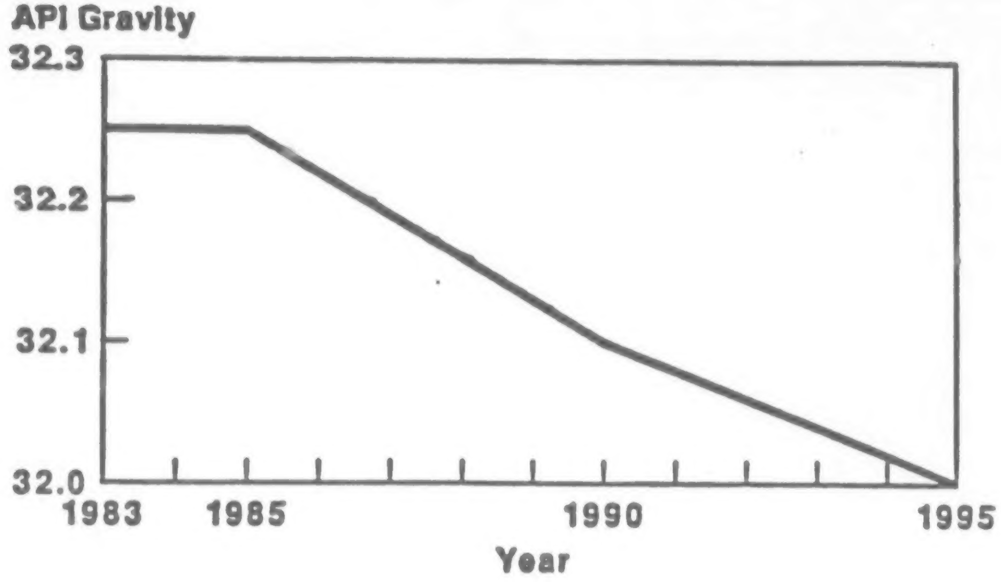
Slide 11

CRUDE OIL QUALITY
SULFUR



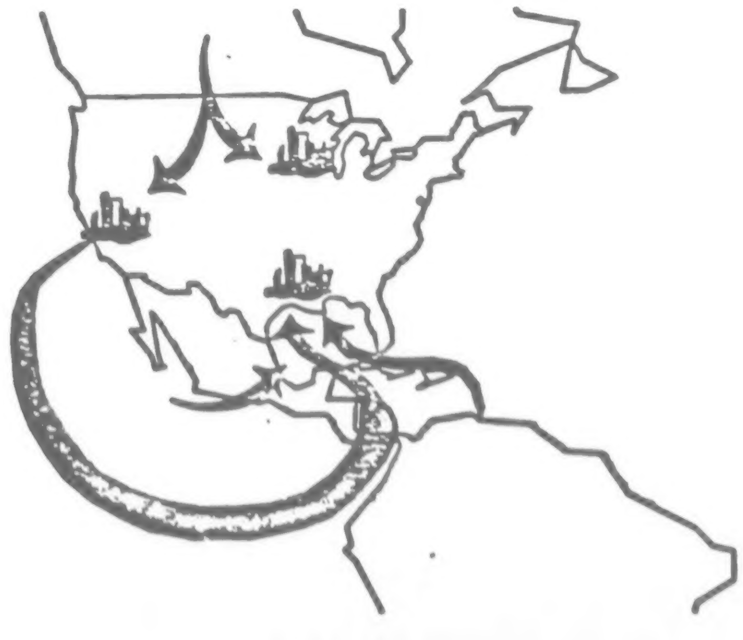
Slide 12

CRUDE OIL QUALITY
GRAVITY



Slide 13

HEAVY OILS



Slide 14

PRODUCT QUALITIES

- Gasoline Octane
- Gasoline Vapor Pressure
- Diesel Sulfur

Slide 16

PRODUCTIVITY

Structure

Efficiency Vs. Expansion
Maintenance And Modification Vs. Construction

Factors

- Safety
- Technology
- Motivation

Slide 18

ORGANIZATIONAL EFFECTIVENESS

Full Utilization Of Abilities
Common Goals
New Organization Culture

OTHERS

- New Environmental Requirements
- Netback Crude Pricing
- Crude / Product Paper Markets
- OPEC

PHILOSOPHY CHANGE?

Upstream	Downstream
Make $	Move Barrels
Make $	Make $

Slide 23, 24

SUMMARY

- Rationalization
  - Challenges
    - Ready

Slide 25

IMPACT OF CANADIAN REGULATORY CHANGES ON CROSS-BORDER TRADE

Canadian Energy Research Institute
International Oil and Gas Markets Conference
Calgary, September 16, 1986

R. Priddle
Chairman, National Energy Board

Highlights	Page
In the year following oil deregulation Canada's crude oil productive capacity grew by 5 percent, but production was unchanged due to a lack of pipeline capacity, the effects of prorationing and a lack of price flexibility.	1
While Canadian oil demand remained stable, exports of crude oil increased by one third and imports by one half. Export prices followed world trends with light crude oil export prices declining from $C 40 per barrel a year ago to $C 15 last July.	2
Natural gas exports are down by 17 percent in the first nine months of the current contract year. This period coincides with the implementation of the Agreement on Natural Gas Markets and Prices, but is also a period marked by declines in U.S. gas prices, declining U.S. gas demand, and significant changes in U.S. gas industry regulation.	2-4
Prices for gas exports by licence have been re-negotiated and some short-term interruptible sales have been made. Export prices now approach those for interprovincial sales, which typically offer a better load factor.	5
Licence holders have been able to average export prices over all sales under a licence to satisfy the minimum export price requirement in relation to the domestic reference price. As a result, since the Agreement of last October 31, all re-negotiated prices for exports of gas by licence have been approved.	5

(check against delivery)

Highlights (Cont'd.)

	Page
The factors having the most impact on gas exports by licence appear to be the 6 percent decline in U.S. gas demand, limitations on pipeline access during the period of transition in U.S. pipeline regulation, priority given by U.S. pipelines to managing lower-48 take or pay obligations and the changing role of U.S. pipelines to being transporters rather than merchants of gas to the detriment of some Canadian gas export contracts.	6
Exports by licence have been at a level of 42 percent of authorized volumes so far this contract year. Volume authorizations have, therefore, not been an impediment to exports by licence. There is no volume restriction for short-term exports by order.	7
Gas exports by short-term interruptible order have faced U.S. pipeline access restrictions but have also been affected by the domestic reference price floor. Short-term interruptible exports grew rapidly after the Agreement, peaking in January, 1986 and then declining as U.S. competitive prices fell below comparable Canadian domestic prices. Short-term interruptible exports have accounted for only 3 percent of total exports in the first nine months of the current contract year.	7-9
Canada's disappointing 1985/86 gas export performance is attributable to weak U.S. gas markets; changing U.S. market structures; and delayed U.S. regulatory change. Although there has been some impact on short-term interruptible sales, the overall decline in gas exports is not significantly relatable to Canadian gas export regulation.	10

Introduction

The year since the last CERI conference on Energy Markets and Trade has been as eventful as any in the past fifteen years of turmoil in world energy markets.

In Canada the oil industry has been operating without domestic or export price regulation or restriction on short-term export volumes. Oil trade patterns have changed as a result and have, of course, also been affected by the world market situation.

Major policy and regulatory initiatives were taken over the past year to allow competitive forces to play on natural gas exports and in domestic markets. These changes stem from the October 31, 1985 Agreement on Natural Gas Markets and Prices and are continuing to evolve as governments and industry come to grips with the detailed decisions needed to implement the intent of the Agreement.

In the United States the federal regulatory regime for natural gas is also evolving and the structure of markets continues to change.

Taken together, the interaction of these regulatory changes in Canada and the U.S. and the overriding influence of the drop in world oil prices have created a volatile mixture which has had significant impacts on cross-border trade over the past year.

Oil Deregulation

My remarks today will focus on natural gas trade; but I would be remiss if I didn't touch on the impacts of oil regulatory changes some one year after the June 1, 1985 implementation of the Western Accord.

It has only been a year, but our regulatory changes already seem like history rather than recent events.

On June 1, 1985:

- the "alphabet soup" of oil price regulation ended;
- volume restrictions on short-term oil exports were lifted;
- transportation subsidies for Canadian crude oil moving to eastern regions ended; and
- oil export charges, import compensation, compensation levies, special Canadian ownership charges and price restrictions were terminated.

What changes to Canadian oil supply patterns followed oil deregulation?

SLIDE 1 - Canadian Crude Oil
One Year After Deregulation

The oil development momentum which had built up over the last two years was well maintained, resulting in a growth in Canada's oil productive capacity of just over 4 percent.

However, production was unchanged at about 250,000 m^3/d as shut-in rose from a negligible proportion of productive capacity in the year through May 1985 to about 7 percent in the year ending May 1986. Observers have attributed this disappointing and costly degree of shut-in to a variety of factors: insufficient pipeline capacity, particularly on Interprovincial's system; the effects of the Alberta prorationing system; and the failure at times of Canadian crude oil prices to respond promptly enough to falling international markets.

Oil Trade and Price

With an open door for exports, this element of disposition increased by 33 percent while imports rose by about 50 percent and domestic requirements for Canadian oil were down very slightly, about one percent.

In terms of pipelines, there has been some greater interest in using the Trans Mountain system, in part to ship the occasional cargo offshore from Vancouver. Interprovincial's western section has been operating near capacity with apportionment being required in some months. That situation should be resolved next year when IPL's capacity expansion program is completed. Meanwhile, some interim relief is being provided by the transfer of small volumes from IPL to Cochin.

The most dramatic changes were of course in respect of producers' prices. The price of light Canadian crude oil for domestic use and for export peaked in November 1985 at about $C 40 a barrel and fell to a low of approximately $C 15 a barrel in July. Over this period the price spread between light and heavy oil also narrowed from about $C 6 to less than $C 3 in some months. These price trends were in direct response to competing world prices.

SLIDE 2 - Canadian Crude Oil Export Price

West Texas Intermediate is the benchmark feedstock which competes with Canadian light crude oil. Prices have ranged from $U.S. 32 per barrel a year ago to $U.S. 10.50 last March. Mexican Maya heavy crude is an indicator of competition for Canadian heavy crude exports. Maya prices have varied from $U.S. 24 to $U.S. 7.50 over the past year.

The Gas Agreement

The October 31, 1985 Agreement on Natural Gas Markets and Prices between Canada, Alberta, B.C. and Saskatchewan committed governments, regulators and the industry to market-sensitive prices in domestic and export markets.

You will recall that the Agreement provided for:

- regionally-determined domestic reference prices as a benchmark for gas export prices on a comparable service basis;
- open orders for short-term gas exports of up to 2 years with no volume restriction;
- the elimination of any incrementality test for short-term orders;
- the elimination of any alternate fuels pricing test for gas competing in export markets; and
- a one-year freeze on domestic Canadian gas prices with large users having the option of negotiating competitive prices with gas suppliers as their contracts expired.

Nobody expected the implementation of competitive conditions in gas markets to be easy and nobody is being disappointed.

Industry's contracting practices, pipeline regulation, the treatment of take-or-pay carrying charges and provincial regulatory policies must all be reconciled with the new domestic gas pricing policy if market sensitive pricing is to be successfully implemented. And just to make life interesting during the transition period, gas prices in U.S. markets have continued to fall.

For gas exports you will recall that the first step away from a uniform regulated export price occurred on November 1, 1984 when exporters were permitted to negotiate export prices subject to a Toronto reference floor price. The response of the industry was impressive. Export volumes in 1984/85 rose by 22 percent, while unit prices were reduced by about 25 percent, and the value of gas exports was maintained at some $C 4 billion.

The Agreement on Natural Gas Markets and Prices continued the momentum towards a competitive framework for gas trade but also reaffirmed some regulatory features that will not change such as:

- provincial removal permit authority;
- essentially cost-based toll regulation of pipelines under NEB jurisdiction;

- consideration of foreseeable Canadian requirements in the approval of long-term gas export licences; and
- assurance that Canadian users have access to prices at least as low as those available to U.S. buyers of our gas.

In this environment of continuing but relaxed regulation I feel that the National Energy Board provides a framework for gas trade which facilitates the operation of a competitive market in conformity with the established policy of governments.

Gas Trade

Having outlined the policy changes over the past year, I want to focus on what has happened in gas export markets and to present my views on why changes have occurred, including the influence of export regulation.

SLIDE 3 - Gas Exports by Licence Holders
and Short-Term Interruptible Orders

Canadian exports started the contract year with a continuation of the strong performance we saw last year. Prices were competitive and licence holders were able to retain access to their traditional markets.

Two major factors quickly changed that positive beginning:

- Total U.S. gas consumption is some 6 percent below last year's level so far this year due to a mild winter, fuel switching and a slower U.S. economy. Industrial and electric utility consumption is off by the largest amount, down 15 to 20 percent relative to the same period last year.
- The implementation of FERC Order 436 was delayed, putting off open pipeline access in the U.S. and introducing some unique situations for Canadian gas trying to compete during this interim period.

In analysing the decline in exports in more detail I find it useful to distinguish between exports by licence holders and exports by short-term interruptible orders.

Exports by long-term licence still account for some 84 percent of the total. In addition licence holders have been using short-term orders as a convenient way of satisfying their contracted export sales pending approval of re-negotiated prices under long-term licences. These short-term orders used by licence holders account for another 13 percent of total exports. The remaining three percent of exports in the current contract year are short-term interruptible exports by order.

Gas exports by long-term licence are suffering losses of about 30 percent this year. When firm orders used by licence holders are included, the decline in exports by licence holders is moderated to 20 percent. In total, including short-term interruptible orders, our exports in the November-July period of the current contract year are off by 17 percent compared to last year and our share of the U.S. market has slipped to about 4 percent from 5 percent.

SLIDE 4 - Gas Exports by U.S. Regional Market

Regionally, the Pacific Northwest and the North Central U.S. markets have been the hardest hit by competition from residual fuel oil. California has also lost sales to fuel oil, notably in the electric generation sector.

While we have suffered setbacks in all of our major regional markets, sales to the U.S. North Central region have been particularly disappointing, falling by 33 percent so far this contract year.

Licence Holders

Looking first at the licence holders - why have exports dropped? Is it price? Is it pipeline access? Are there other contracting issues?

There are no simple answers - but I would like to give you my thoughts on these questions.

Prices for licensed exports, like those by order, must comply with the regional reference price. However, in interpreting this policy, the NEB has provided pricing flexibility to exports by licence, permitting prices to be averaged across the total export volume for each licence on an annual basis.

As a result, licence exporters have had the flexibility to re-negotiate contracts and to compete in growing spot markets while satisfying the border reference price requirement.

This approach has caused some controversy because gas has in some cases been exported at prices below the recognized regional reference price. However, on average licences are still returning export border prices which exceed by a considerable margin both the relevant regional reference prices and prices from short-term interruptible exports. For example, comparing netbacks to the producing provinces after average transportation tolls are deducted, over the first nine months of this contract year licences returned an average $U.S. 2.30 per MMBtu, while interruptible orders were near $U.S. 2.00.

SLIDE 5 - Producing Province Netback

Average producing province netbacks from exports have declined sharply in recent years, and now approach those from sales to domestic markets. In addition to average netback revenues, load factors are also a consideration. Domestic sales continue to offer better load factors on average than do export sales. For example, the average load factor for gas moving east from Alberta on the TransCanada system is 85 percent for domestic sales while export sales were at a level of about 70 percent of contract volumes in 1985. The recent poor performance of exports is further reducing export load factors.

Domestic sales have started to respond to market competition though direct sales and competitive marketing programs at lower prices. The 1985/86 bar for domestic sales shows the impact of these lower prices on average netbacks; down about 20 cents. Prices for short-term interruptible sales included in these domestic and export netback averages have been declining throughout the current year. Netbacks on short-term interruptible exports and domestic sales are currently near the $C 2 per gigajoule level.

The decline in export netbacks is largely due to the re-negotiation of export prices under existing licences. Since the October 31 Agreement, export licence holders have acted to use the newly-available pricing flexibility, and the Board has examined and approved all re-negotiated export prices.

Regionally, in California and the Pacific Northwest, exporters have been particularly aggressive in re-negotiating prices and participating in spot sales, and export prices have declined by about 15 percent. The average export price for licences in these areas is closer to the relevant floor price than the average of all licensed export sales - but the lower price has been a factor in reducing the erosion of our market share. By contrast licence exporters in some other regions appear to have taken less advantage of the available export price flexibility. Volume losses as a result have been more severe. Alternatively, the market for Canadian gas in these regions may be less responsive to price given the current market situation of low oil prices and the take-or-pay difficulties of several U.S. pipelines.

Two other factors have acted to limit exports by licence holders in recent months. They are the regulatory environment in the U.S., notably the delay in implementing the "open access" provisions of FERC Order 436; and the changing role of the interstate pipelines, which increasingly are becoming transporters of gas for others rather than being gas merchants.

The problem facing Canadian exporters is two-fold: Firstly, exporters are unable to initiate sales into new markets until pipelines connecting with those markets from the Canadian border open their systems. Secondly, Canadian exporters who sell "system gas" under long-term contracts to interstate pipelines (about 50 percent of our exports are sold this way) have found their market seriously eroded by direct sales of U.S. gas under grandfathered transportation agreements.

The problem is further aggravated by the fact that some interstate pipelines, burdened with high take-or-pay charges on their supply contracts with U.S. producers, have found it to their advantage to "release" some of the gas from contract for direct sale by the producer, further shrinking the market for system suppliers, including some Canadian exporters.

SLIDE 6 - U.S. Importers
Canadian Gas Volumes

The shrinking market for system gas is particularly evident for such importers as United and ANR. The result has been some major export reductions particularly in the North-Central region. The concentration of our export sales on interstate pipelines' system supply in this region has proven to be a problem in the current transitional period in U.S. pipeline regulation.

In contrast, exports to California and the U.S. North East, as well as some sales in the central region, are contracted more directly to gas distributors and have not been subject to the same degree of volatility as pipelines move from a "merchant" role, to a "transportation" role and as direct sales grow. These more direct sales are generally represented by PGE, SOCAL and "others" on this slide.

Thus the recent weakness in exports by licence is attributable to weakness in U.S. gas demand and to the changing structure of the U.S. market. Our price restrictions have not been a limiting factor. I have already noted the flexibility allowed licence holders in meeting our price guidelines.

It goes without saying that volume controls have not been a factor. To date this year, exports are running at only 42 percent of authorized levels. The Board recently relaxed its export surplus determination procedure and has estimated that some 10 exajoules of incremental authorizations might be permitted under the new procedure.

I want also to note that the Board is giving prompt attention to applications for long-term licences where a gas supply is available; provincial removal authority has been received; new facilities are not required; and where there is a reasonable prospect of early commencement of sales. For example, export hearings are scheduled for A&S and Progas to begin on September 23 and for Shell on October 7 to examine export applications for which these conditions had been met. In light of the changing markets, we will also be reviewing existing unused licences authorized in 1983, when these licences reach their sunset dates early next year.

Interruptible Exports by Order - Non Licence Holders

Moving now from export licence holders, which account for 97 percent of exports, to interruptible exports by order, the issues and market conditions are somewhat different.

Recall that the Agreement on Natural Gas Markets and Prices removed volume limitations on exports by order with terms of two years or less and removed the incrementality test. The floor price test was retained but on a regional basis. The monthly average price for exports by short-term order must be not less than the regional Canadian reference price for equivalent service. This has generally been interpreted by the Board to be the regional wholesale interruptible price to the local distribution utility.

The thrust of the new policy was to encourage short-term orders as a vehicle for Canadian exporters to compete in the burgeoning U.S. spot market. It was hoped exports by order would supplement rather than displace licence exports, helping to prevent erosion in aggregate export volume and Canadian market share.

To date, some 50 export orders have been issued, in most cases within 3 days of the application having been received. In contrast, mirror U.S. import approval still requires a minimum 45 days. As I noted earlier, interruptible exports by order make up about 3 percent of the total export volume so far this year - other orders are being used by licence exporters to meet firm contract sales to existing importers.

SLIDE 7 - Gas Exports
Licence Holders and Short-Term Interruptible Orders

It is clear from this slide that short-term interruptible exports have not as yet succeeded in providing the vehicle by which Canadian exporters can more actively compete in the U.S. spot markets.

Short-term interruptible sales quickly accelerated soon after the policy changes and lower regional floor prices were implemented in November, 1985. These exports peaked in January at 5.9 $10^6 m^3/d$ (200 mmcf/d) but had dropped to 0.8 $10^6 m^3/d$ (29 mmcf/d) by April. However, almost all of these exports have been to the Pacific Northwest region.

The question is; why did short-term exports only compete in the Pacific Northwest and why have they tailed off since January? The most immediate factor appears to have been the lack of access to U.S. pipelines serving other regions during the transition to "open access" in the U.S. During the first months following the shift to a regional floor price it would seem that additional short-term interruptible sales could have been made if pipeline access had been universally available.

The floor price became a factor influencing short-term interruptible sales a few months after the new policy was introduced.

In January world oil prices dropped. By February fuel oil prices began to decline and spot sales of Canadian gas to the Pacific Northwest started to drop off. By April U.S. gas spot market prices began to reflect the oil price decline and U.S. spot prices dropped below our regional reference price.

SLIDE 8 - U.S. West Coast Market
Spot Price Vs. Regional Reference Price

This slide illustrates the interaction of the domestic reference price and U.S. competitive prices, using the U.S. West Coast region as a sample market.

When the reference price was changed from the Toronto reference point to a regional reference in November of last year, the domestic reference price for interruptible exports crossing the border in B.C. dropped below the U.S. competitive spot price. This gave exporters the opportunity to compete for spot sales and, as we saw, short-term interruptible sales rose quickly, peaking in January.

The U.S. spot price decline after January ended that price opportunity for spot sales and put the NEB in a tough position. The Agreement between Canada, Alberta, B.C. and Saskatchewan clearly defined the floor price policy. B.C. and Alberta re-affirmed their commitment to the policy in recommending to the Board that exports at prices below the floor not be allowed.

Continuing into June 1986, the Board was compelled to deny several applications for short-term exports because evidence was not presented which indicated that Canadian consumers in the area adjacent to the export point had access to gas priced as low as the proposed exports. In fact the Board issued cease and desist orders to stop sales under three interruptible orders when export prices fell below Canadian prices for similar gas service in the area of the export point.

By July evidence was accumulating that discounts from administered prices were becoming increasingly available to Canadian gas users. Evidence of discount priced domestic sales was presented to the Board by a number of applicants and several orders were approved at levels which had previously been judged to be below prices charged to Canadians for similar gas service.

Critics of the Board's actions have suggested that the Board changed the floor price policy over this period or that the Board had reversed earlier decisions. In fact the policy is defined in the Agreement on Natural Gas Markets and Prices and has not changed. It remains the case that Canadian buyers in the area adjacent to the export point must have access to gas at prices at least as low as those for comparable export sales.

In applying the policy the Board has been responsive to evidence presented in a manner consistent with the Board's desire to encourage short-term export sales.

Nonetheless, I think there is no doubt that the floor price policy has tended to discourage some short-term interruptible exports. It has been a much more important factor in exports to western U.S. markets than in the North Central region, where limited access to U.S. pipelines has probably been more important.

I expect that the floor price will be much less important as a restricting factor after November 1, as Canadian prices are renegotiated to reflect current energy market realities.

Concluding Comments

I conclude from my analysis of the recent performance of Canadian gas exports that the difficulties we are now facing relate to the weakness of U.S. demand for gas, to the changing structure of the U.S. market as direct sales replace sales of system gas and to the slow pace of change in the U.S. regulatory environment which has severely limited pipeline access for Canadian short-term interruptible gas.

It cannot be convincingly argued that Canadian regulatory policy vis-a-vis gas exports, or its implementation, has been an important constraining factor. Volume constraints have obviously not been important nor have price constraints been an impediment to licence holders. Price constraints have been a factor tending to restrain short-term interruptible exports particularly in the Pacific Northwest and California markets. But it is far from clear that they were the critical factor. Short-term exports are bound to be limited in volume until the open-access provisions of FERC Order 436 become effective.

Until recently our outlook was that total exports would be down by abcut 15 percent for the current year, at about 800 Bcf. However, recent export performance, continuing problems with U.S. pipeline access, surplus gas supply which is increasingly being sold directly from producers to end users, and the fierce price competition which has developed in U.S. gas markets, seem to indicate that exports could decline by even more than the 17 percent indicated by the first nine months' performance.

The Board, for its part, will continue to work towards a regulatory framework for gas exports which will be flexible and minimize this volume loss, subject to the policies of the Government of Canada.

The Honorable Anthony G. Sousa
Acting Chairman
Federal Energy Regulatory Commission

Changes in U.S. Gas Regulation and the Impact on Canadian Trade

Remarks at The International Oil
and Gas Markets Conference

Calgary, Alberta
September 16, 1986

I appreciate the opportunity to participate on this panel dealing with the impact of U.S. and Canadian regulatory changes on natural gas trade between the two countries. I have been asked to discuss the impact of regulatory change South of the border, and there is much to talk about.

Important U. S. Regulatory Changes

In the past two years there have been significant changes in U.S. regulation of the natural gas industry which relate to trade with Canada. These changes have taken place at both the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC). The changes were implemented to respond to the increased competition occurring in the industry and to facilitate the development of that competition even further.

U.S. Regulatory Responsibility Related to Canadian Imports

The responsibility for regulating imported gas from Canada into the U.S. is shared by two agencies. In 1977, the Secretary of Energy was given Section 3 import authority under the Natural Gas Act. This means that DOE must approve all imports of gas from Canada. The Federal Energy Regulatory Commission has responsibility for other aspects of regulation related to imported Canadian gas. This authority includes the responsibility for such things as approving resale rates in the U.S., certification of new facilities, and transportation services.

DOE Regulatory Changes

As you know, until recently, Canadian gas imports were heavily regulated on both sides of the border. Between 1974 and 1984, the National Energy Board established both the export price and volumes. In the U.S., the Federal Power Commission (the predecessor to the FERC) and then the Economic Regulatory Administration (within DOE) reviewed the price and other significant terms of import arrangements. A key aspect of this regulation was a uniform border price, which at its highest was $4.94 (U.S.) per Mcf. That price, coupled with increased domestic production in the lower 48 and a downturn in U.S. demand, resulted in significantly reduced takes of Canadian gas in the early part of this decade.

In 1984, both governments began to change their regulatory approaches. In February, the U.S. Secretary of Energy promulgated a new import policy which directed ERA to review import authorization requests with special attention to the competitiveness of the underlying contracts. The DOE guidelines emphasized that agreements should be structured so as to supply natural gas to American consumers at competitive prices and be responsive to changes in the markets served. Since 1984, the Government of Canada has implemented new policies with a similar emphasis on market responsive contracts.

FERC Regulatory Changes

During the past two years, the Commission has taken three major initiatives aimed at fostering competition in U.S. natural gas markets. All three have significance for Canadian imports. In chronological order these Commission actions are Order Nos. 380, 436 and 451.

1. Order No. 380

Order No. 380, known as the minimum bill rule, went into effect August 1, 1984. This rule eliminates variable costs from the minimum commodity charge portion of natural gas pipeline sales tariffs. It prohibits interstate pipelines from recovering variable costs, mainly purchased gas costs, for gas not taken. Such recovery, the Commission concluded, impedes competition and deprives pipeline customers, especially partial requirements customers, of the opportunity to acquire a least-cost supply mix.

2. Order No. 436

The second major FERC action was the issuance of Order No. 436 last October. This Order established a program for pipelines to transport shipper-owned gas. It replaced a myriad of prior programs, two of which had been terminated by a U.S. Circuit court. The court found that these programs did not afford captive customers the same opportunity as non-captive customers to shop around for cheaper supplies and have those supplies transported.

The premises of Order No. 436 are that gas is a commodity separate and distinct from transmission and that the wellhead market is workably competitive. For that competition to work, sellers and buyers must have access to transportation and transporters must have the flexibility to provide service on a timely basis. Some of the important steps taken in Order No. 436 to promote competitive natural gas markets are as follows:

First, Order No. 436 provides for flexibility in negotiating agreements by allowing pipelines to implement transportation with little or no prior regulatory approval. Self-Implementing it also removes all restrictions found in various forms under the previous programs on what gas could move to whom. Hence, for example, there is no restriction on transporting Canadian gas as there was under the old blanket certificate program.

Second, nondiscriminatory open access to transportation is required. The decision whether to become an Order No. 436 carrier is voluntary. However, once a participating pipeline decides to transport for one party it must transport for all parties, within capacity limits, on a nondiscriminatory basis.

Third, the Order provides that a pipeline's firm sales customers must be given the opportunity to adjust their gas purchase obligations in order to take advantage of the new transportation opportunities. This is accomplished by allowing customers, over a five-year period, to either totally eliminate their contract demand service or to completely convert their contract demand entitlement to a right to firm transportation service.

Fourth, Order No. 436 provides for increased accountability of pipelines for their business decisions. Transportation rates are designed to provide full cost recovery only if the pipeline does business effectively. Moreover, under the optional expedited certificate procedures, pipelines that construct new facilities are not guaranteed cost recovery. The business risk for new facilities constructed under expedited certificates is borne by stockholders.

Fifth, the Commission took action to allow pricing flexibility so that prices can respond to different conditions of supply and demand. In the sale of transportation services pipelines are free to adjust rates at any time within a given range. Also, peak and off-peak rates are required when justified by differences in pipeline use. Moreover, in the gas commodity market, unbundling will enable prices to fluctuate up and down with changes in consumer demand and wellhead production.

Sixth, the Order reduced regulatory barriers to entry. Entry is facilitated by the optional expedited certificate procedures of the rule. Under these procedures, applications for new sales and transportation service will receive expedited treatment and pre-granted abandonment, provided that the applicant is willing to assume all of the risk for its venture. The certificating of competing applications -- previously unheard of -- will be considered.

Finally, in line with the premise of a competitive wellhead market, Order No. 436 established new abandonment procedures for producers. These procedures provide for expeditious consideration of abandonment applications for shut-in gas, gas subject to expired contracts, or gas released by a pipeline as part of contract renegotiation or a take-or-pay buyout. Previously, abandonment was generally granted only when dedicated wells had played out and gas no longer could effectively flow. Also the Order lays the premise for an expanded standard for measuring when abandonment is in the public interest. Historically, public interest had been defined as the well-being of the pipeline and its customers to whom the gas was dedicated. The new expanded view puts the emphasis on the national benefits of making increased supplies of old gas available to the national economy.

3. Order No. 451

In June of this year the Commission issued Order No. 451 dealing with gas prices still regulated pursuant to the Natural Gas Policy Act (NGPA). This rule has important implications for a more competitive wellhead market.

A recurring problem in the federal price regulation of gas has been the setting of wellhead prices that do not always reflect market circumstances. Thus, in times of relative scarcity the price has been too low while in times of relative abundance it has been too high. In 1978, the NGPA provided for the phased deregulation of wellhead prices for certain categories of gas under a Congressionally mandated schedule. By January 1, 1985, price controls on more than 50 percent of U. S. supplies had been lifted. Still, substantial quantities of gas are currently subject to NGPA price controls.

In Order No. 451, the Commission found that the pricing structure for "old" gas is unjust and unreasonable, because it creates serious market distortions by preventing that gas from being responsive to the market. Consequently, we collapsed the numerous vintages of "old" gas into one vintage, and established a single, alternative ceiling price at the highest level allowed by the NGPA for "old" gas. This maximum lawful price is currently $2.58/MMBtu, and is subject to an inflation adjustment factor over time. It is based on an estimate of the replacement cost of gas supply.

The cornerstone of Order No. 451 is the good faith negotiation or GFN procedure which can provide upward pricing flexibility for low-cost old gas and downward pricing flexibility for newer, higher cost gas. Under the GFN procedure, a producer may exercise a one-time option requesting that a purchaser nominate a new higher price that it is willing to pay for certain old gas identified by the producer under contract between the parties. If the purchaser nominates the ceiling price, the offer must be accepted by the producer. However, if a lower price is nominated, the producer is free to reject the offer and sell the gas to a third party. This part of the procedure provides upward pricing flexibility for certain gas.

Downward pricing flexibility for high cost-gas is provided by another aspect of the procedure. A purchaser, if contacted by a producer about higher prices for old gas, may ask the producer to nominate new lower prices that it is willing to accept for any gas (both old and new) under any other existing contract that covers some old gas. This means that the purchaser is free to request a significantly lower price for new or decontrolled gas if that gas is sold pursuant to a contract that also includes some old gas. If the producer nominates a price that the purchaser is unwilling to pay, the purchaser is free to terminate purchase of all or part of that gas. Conversely, if the purchaser demands a price that is unacceptable to the producer and terminates the purchase, the producer may sell the gas elsewhere.

Any purchase by a new buyer is subject to a right of first refusal by firm sales customers of the existing pipeline purchaser, if that existing purchaser is not an open-access transporter under Order No. 436. The purpose of this provision is to protect the firm sales customers' access to an adequate supply of gas at reasonable cost. If the pipeline is an Order No. 436 transporter, there is no need to provide firm sales customers a right of first refusal. This is because these customers have the opportunity to purchase gas from any producer connected to that pipeline and have the gas transported to them.

Order No. 451 also provides limited transportation authority applicable to any pipeline that does not transport under Order No. 436. Under this provision, the pipeline must transport gas whose sale has been abandoned or released by either the producer or the pipeline under the good faith negotiation procedure. This gas is to be transported to any of the pipeline's existing customers (sales as well as transportation) and interconnected pipelines.

Impact of Regulatory Changes on U.S. - Canadian Trade

I turn now to the impact of the regulatory changes just described on U.S.-Canadian trade. I will start with a brief review of what has been happening recently in terms of cross-border trade.

U.S.-Canadian Gas Trade Since 1983

The U.S. exports some natural gas to Canada. However, the amount is so small in comparison to imports that I will concentrate my remarks entirely on imports from Canada into the U.S. There are three things I would like to highlight about these imports since 1983.

First, prices have dropped dramatically. The average price per Mcf paid by interstate pipelines fell from $4.94 in 1983 to $3.17 in 1985. The December 1985 price was $2.78, and the average spot price for the second quarter of 1986 was $1.34.

Second, the flowing volumes have increased significantly. Imports jumped from 712 Bcf in 1983 to 926 Bcf in 1985 -- a 30 percent increase. However, the volumes actually imported are a fraction of the total authorized by ERA, and less than the past high of 1,027 Bcf in 1973. Less than 50 percent of the authorized long-term volumes and less than one percent of the short-term volumes are currently flowing.

Third, Canadian imports have gained market share. In 1983 they represented 4.2 percent of total U.S. consumption. The 1985 figure was 5.3 percent.

Impacts of Regulatory Change

The impacts of the DOE import policy changes are easy to determine. The price and volume changes that I just discussed would not have happened without the new DOE policy and the important changes announced by the Government of Canada beginning in 1984.

With the exception of Order No. 380, the impact of the Commission's regulatory changes is more difficult to assess. Undoubtedly, the minimum bill rule, which allows partial requirements customers to swing away from their pipeline suppliers, has generated competition for imported gas. Much of the load of most U.S. importer-pipelines involve such customers. The other two rules are too new to determine precisely their impact on imports. Potentially, they could both increase and decrease imports.

There are several reasons why increased trade may occur, especially under Order No. 436. First, buyers in the U.S. will have a greater ability to shop around among alternative suppliers, including Canadian suppliers. Second, buyers and marketing entities of all types hopefully will have greater access to pipeline facilities needed to move Canadian gas to market. Third, new facilities needed for moving Canadian gas in the U.S. may be constructed with less regulatory delay. Fourth, pipelines and other buyers may search harder for lower cost supplies because they are made more accountable for their business decisions.

I hasten to add an important caveat to this discussion. The volume of imports from Canada will depend far more on the relative costs and prices of gas in the two countries than on the regulatory changes implemented by the Commission. If prices are lower in the U.S., buyers will purchase from U.S. suppliers. Along this line, Order No. 451 may have the effect of decreasing purchases from Canada. This could be the case if U.S. wellhead prices decrease and the production of low-cost old gas increases. Accordingly, Order No. 451 may lead to a reduction in the low-cost gas cushion of some pipelines. This cushion permits pipelines to buy higher cost gas, roll it in with the lower cost supplies, and market it at an average price acceptable to buyers. Hence, to the extent Canadian gas is marketable due to this cushion, it will be affected by Order No. 451.

Future Regulatory Issues and Pending Matters Related to U.S.-Canadian Trade

There are several other matters currently before the Commission that directly relate to U.S.-Canadian trade. One of these is the "as-billed" issue in U.S. sales rate design, and the others relate to certificate applications for the construction of facilities to carry Canadian imports.

As-Billed practice in U.S. Sales Rate Design

The as-billed practice currently followed by the Commission in U.S. pipeline rate design has been strongly criticized, in part because allegedly it leads to uneconomic purchases, including Canadian imports. This practice allows a pipeline to pass along to its customers the charges it incurs in purchasing gas from another pipeline, in whatever form those charges are incurred (demand or commodity). The issue is now before the Commission in several pipeline rate cases.

The as-billed issue gained prominence after the new export policies of the Canadian Government became effective in 1984. As I mentioned before, prior to that time, Canadian gas was sold at a uniform border price expressed in terms of a single volumetric rate. The new policy allows buyers and sellers considerable freedom to negotiate their own pricing arrangements. As a result, most Canadian gas is now sold to U.S. purchasers under a two-part rate.

Numerous U.S. entities, including producers, pipelines and their customers, are voicing opposition to the as-billed practice because U.S. purchasers are passing Canadian demand charges along to customers as billed. The problem, they claim, is that the Canadian demand charge includes costs not allowed in the demand charge under U.S. ratemaking methodology. Thus, it is alleged that the demand charge is more heavily loaded and the commodity charge is lower than if the gas were purchased in the U.S. As a result, it is argued that U.S. suppliers (both pipelines and producers) are put at a competitive disadvantage because they are competing against an artificially depressed commodity charge which serves as the marginal rate for customer purchase decisions.

Certificate Applications Relating to Canadian Imports

In the area of new service, the Commission is currently considering several certificate applications to construct new pipeline facilities that would carry Canadian gas.

1. California Enhanced Oil Recovery Applications.

Several certificate applications have been filed for construction of new pipeline facilities to supply gas to central California for use in enhanced oil recovery operations. Competing interstate pipeline applications have been made by sponsors of the Kern River, the Mojave and the El Dorado projects.

All three proposals include importation of Canadian gas. Kern River involves imports of gas from Westcoast Transmission to be transported by Northwest Pipeline. El Dorado involves imports of gas from TransCanada Pipe Lines. The Mojave application mentions Canadian imports as one of its potential sources of supply. In conjunction with the above proposals, Northwest, El Paso and Transwestern pipelines propose to construct and operate facilities and to provide firm transportation service; Northwest proposes to transport up to 350 MMcf/d of gas from Canada to the Kern River project.

In May of this year, the Commission issued an order consolidating all of these proceedings for a comparative evidentiary hearing, including environmental matters, before an Administrative Law Judge. A schedule for discovery and the preparation of testimony has been established. The hearing will begin in May 1987.

2. Applications to Serve Northeastern U.S. Markets

Since 1980, numerous applications to serve the Northeast with Canadian gas (primarily to offset the decline in the Texas/Louisiana Gulf reserves) have been filed at the Commission. After some limited authorizations were granted, the major long-term proposed projects boiled down to three competing proposals -- the NIPS proposal (NIPS stands for Niagara Interstate Pipeline System, a consortium of Tennessee, TransCanada, Transco and Texas Eastern Affiliates), an ANR-Ohio Interstate Proposal, and a Natural Gas Pipeline proposal. NIPS would move the gas through TransCanada. The Other two would use the ANGTS prebuild. In 1984, all three proposals were consolidated in what's called the Boundary II proceeding.

The various project participants have been in the process of renegotiating the gas import contracts, largely to reflect the market-sensitive pricing through a two-part rate structure that I mentioned earlier and new project configuration. The hearings were recessed pending the completion of whatever new import arrangements may emerge.

In the past year, the Boundary proceeding has undergone several changes. In December 1985, sponsors of one project, ANR and Nothern, withdrew their application. Then in February, March, and April 1986, ANR, Great Lakes and Transco filed the Erie/Transylvania proposal, partially under the Commission's new optional expedited certificate procedures established in Order No. 436 and also under regular Section 7(c) procedures. The Erie/Transylvania project would move Canadian Gas through the Great Lakes and ANR systems, then through the new facilities, and then into the Transco system. The Iroquois Gas Transmission System also filed in May of this year an application to import gas to New York City.

Because of the many changes in the pending applications, the Administrative Law Judge held a public conference this past May to hear summary statements of all amended applications regarding transportation projects to serve the U.S. Northeast. The project sponsors were not prepared to present any clarification on amended applications at that meeting and departed without determining how most efficiently to proceed. As a result of project redefinition, a number of withdrawal petitions may occur. Also, the Commission still has under review the Erie/Transylvania and Iroquois applications.

Conclusion

As I have discussed, U.S. natural gas regulation can influence the extent and nature of cross-border trade. However, it is my belief that in the long run economic forces in the market place will have a much greater impact than U.S. regulatory policy. This policy has been designed to enable competitive market forces to work more effectively, rather than to achieve specific outcomes with respect to Canadian trade. Thus, over time competition in natural gas markets and with alternative fuels will be the main driving force behind U.S.-Canadian trade. The U. S. government's role I believe will be limited to monitoring the actions of the market and, where the market is sufficiently competitive, the government should step aside.

Thank you.

Western Gas
Marketing
Limited

IMPACT OF
U.S. AND CANADIAN REGULATORY CHANGES
ON CANADIAN GAS EXPORTS

C.K. (KEN) ORR
PRESIDENT, WESTERN GAS MARKETING
ADDRESS TO THE
INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

CALGARY, SEPTEMBER 16, 1986

C.K. ORR

ADDRESS TO THE

INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

"LOGO"

IMPACT OF
U.S. AND CANADIAN REGULATORY CHANGES ON CANADIAN GAS EXPORTS

SEPTEMBER 16, 1986

GOOD AFTERNOON LADIES AND GENTLEMEN.

I AM SUBSTITUTING FOR GERRY MAIER PRESIDENT OF TRANSCANADA PIPELINES AND CHAIRMAN OF WGML IT'S INDEED AN HONOR TO BE SHARING A PODIUM WITH SO MANY ACCOMPLISHED EXPERTS IN THE ENERGY INDUSTRY.

I WAS RELIEVED TO HEAR SOME OF YOUR SPEAKERS COMPLAIN THAT THIS IS A DIFFICULT TIME TO ANALYZE EVENTS AND AN ALMOST IMPOSSIBLE TIME TO PREDICT TRENDS.

"TITLE SLIDE"

I FULLY SUBSCRIBE TO THEIR COMPLAINTS, HOWEVER, THIS INDUSTRY IS CHANGING QUICKLY AND IF YOU'RE ACTUALLY IN IT, THERE IS NO BETTER

TIME THAN NOW TO LOOK AT THE IMPACT THAT REGULATORY CHANGE HAS IMPOSED ON CROSS BORDER TRADE.

AS THE LOOMING DATE OF NOVEMBER 1ST APPROACHES, PREPARATION FOR ANY FORUM IN WHICH YOU HAVE AN EXTERNAL OPPORTUNITY TO AIR YOUR VIEWS IS A WELCOME AND HEALTHY EXERCISE.

"LOGO"

WGML ONLY BEGAN OPERATIONS ON JANUARY 1ST OF THIS YEAR TO ACT AS TRANSCANADA'S AGENT TO MARKET THE VOLUMES OF GAS IT HAS UNDER CONTRACT WITH WESTERN PRODUCERS. WE SET OUT INTO AN EXTREMELY COMPETITIVE MARKET PLACE WHICH WAS EAGER TO TASTE THE FRUITS OF DEREGULATION.

LET ME BRIEFLY REVIEW WGML'S ACTIONS IN RESPONSE TO THIS COMPETITIVE ENVIRONMENT. I WILL LOOK FIRST AT OUR CANADIAN MARKETS TO REVIEW WHAT'S HAPPENED DURING THE INTERVENING 8 MONTHS.

SLIDE A
"WGML CANADIAN EFFORTS"
OBJECTIVES/PERFORMANCE

OUR INITIAL EFFORTS FORCUSED ON RETAINING AS MUCH OF THE EXISTING CANADIAN MARKET AS POSSIBLE WHILE AT THE SAME TIME ATTEMPTING TO PREVENT PRICES FROM ENTERING A FREEFALL CONDITION. OUR EFFORTS IN THAT AREA HAVE MET WITH BOTH SOME SUCCESSES AND SOME DISAPPOINTMENTS. WE HAVE RETAINED THROUGHOUT THE CONTRACT YEAR (THAT ENDS THIS OCTOBER 31ST) 90% OF OUR MARKET IN THE FACE OF INTENSE COMPETITION FROM DIRECT SELLERS BOTH IN ALBERTA AND SASKATCHEWAN. THIS HOWEVER HAS RESULTED IN THE AVERAGE PRICE DECLINING BY ABOUT 20¢/GJ AT THE ALBERTA/SASKATCHEWAN BORDER.

55 BCF OF COMMERCIAL AND INDUSTRIAL MARKETS IN CENTRAL CANADA HAVE HOWEVER BEEN LOST TO DIRECT SELLERS THROUGH DEEP DISCOUNTS APPROACHING IN SOME CASES AS MUCH AS 50%, WE UNDERSTAND, OR $1.40 PER GJ OFF THE ALBERTA BORDER PRICE.

WGML'S VICE PRESIDENT OF CANADIAN SALES AND HIS STAFF HAVE JUST CONCLUDED KNOCK-EM-DOWN, DRAG-EM-OUT NEGOTIATIONS WITH OUR 4 MAJOR CUSTOMERS IN CENTRAL CANADA. LAST WEEK WE PRESENTED THE RESULTS OF OUR EFFORTS TO THE PLAYERS AT THE OTHER END OF THE TCPL PIPELINE (THAT IS, OUR 722 PRODUCERS HERE IN THE PROVINCE OF

ALBERTA) BECAUSE UNDER EXISTING LEGISLATION, WE ARE REQUIRED TO DEMONSTRATE PRODUCER SUPPORT FOR PRICE CHANGES FOR GAS MOVING IN INTERPROVINCIAL TRADE.

LET ME RECAP SOME OF THE HIGH POINTS OF LAST WEEK'S PRODUCER MEETING.

SLIDE B
"DISTRIBUTOR AGREEMENTS"

WE ANNOUNCED THAT WESTERN GAS MARKETING HAD REACHED AGREEMENT WITH FOUR CENTRAL CANADIAN DISTRIBUTORS (LISTED ON THIS SLIDE) WITH RESPECT TO ARRANGEMENTS SURROUNDING THE PRICE OF NATURAL GAS TO BE SOLD TO THEM UNDER OUR EXISTING FIRM SALES CONTRACTS.

THE AGREEMENTS REACHED ARE TO TAKE EFFECT AS EARLY AS SEPTEMBER 8, 1986 AND RUN THROUGH TO OCTOBER 31, 1988.

THEY ARE SUBJECT TO PRODUCER, PROVINCIAL AND FEDERAL GOVERNMENT APPROVALS, AND ARE DESIGNED TO ENSURE THE NEW COMMODITY PRICES ARE PASSED ON TO THE END USERS IN A MANNER ACCEPTABLE TO BOTH WGML AND THE DISTRIBUTOR. I SHOULD NOTE THAT THIS APPROVAL PROCESS IS ALREADY UNDERWAY, AS WE TODAY SENT OFF 722 LETTERS TO OUR PRODUCERS REQUESTING JUST THAT.

SLIDE C

"DISTRIBUTOR MARKETS"

EACH DISTRIBUTOR'S MARKET HAS BEEN DIVIDED INTO THREE SECTORS. RESIDENTIAL AND SMALL COMMERCIAL MAKE UP THE "CORE MARKET" AND ACCOUNT FOR 282 BCF/YEAR OR ABOUT 36%. THE VULNERABLE COMMERCIAL AND INDUSTRIAL MARKET HAS BEEN CLASSIFIED AS THE "DISTRIBUTOR MARKET", AND ACCOUNTS FOR 265 BCF/YEAR OR 34%. THE LARGE INDUSTRIAL MARKET OF ABOUT 70-80 CUSTOMERS, MAKES UP THE "CUSTOMER SPECIFIC MARKET" AND ACCOUNTS FOR 230 BCF/YEAR OR 30%.

SLIDE D

"PRICING STRUCTURE"

THE AGREEMENTS PROVIDE FOR NEW BASE PRICES THAT WHEN NETTED BACK TO THE ALBERTA BORDER WILL YIELD $2.60 PER GJ FOR THE CORE MARKET GAS.

IN ADDITION, TWO MARKET "FUNDS" HAVE BEEN ESTABLISHED TO ALLOW THE CONTINUED ADMINISTRATION OF ALL CMP'S THAT WE HAVE IN PLACE, AND TO ADDRESS THE NEEDS OF ALL VULNERABLE COMPETITIVE MARKET VOLUMES.

SLIDE E
"PRICING STRUCTURE"
BUILDING BLOCK

THE OVERALL OBJECTIVE OF OUR PRICING STRUCTURE IS TO RETAIN, RECAPTURE, AND EXPAND MARKETS, WHILE AT THE SAME TIME PROVIDING THE BEST POSSIBLE NETBACK PRICE TO OUR PRODUCERS. OUR PROPOSED STRUCTURE IS SHOWN GRAPHICALLY IN THIS SLIDE.

TO REPEAT:

- THE CORE MARKET REPRESENTS THE RESIDENTIAL AND NON-VULNERABLE COMMERCIAL CUSTOMERS.

- THE DISTRIBUTOR MARKET FUND WILL ADDRESS THE REQUIREMENTS OF THE VULNERABLE COMMERCIAL AND SMALL INDUSTRIAL MARKET, REPRESENTING APPROXIMATELY 23,000 CUSTOMERS. THE COMPETITION IN THIS MARKET SECTOR COVERS THE ENERGY SPECTRUM: GAS-TO-GAS, HFO, #2 FUEL OIL AND ELECTRICITY. THIS FUND WILL BE ADMINISTERED BY THE DISTRIBUTOR IN ACCORDANCE WITH DISCOUNT SCHEDULES APPROVED BY WGML.

- THE CUSTOMER SPECIFIC FUND WILL ADDRESS THE REQUIREMENTS OF THE LARGE INDUSTRIAL MARKET REPRESENTING 70-80 OF THE LARGEST GAS USERS IN CENTRAL CANADA. THE COMPETITION HERE IS PRIMARILY GAS-ON-GAS BUT HFO IS ALSO A FACTOR. THIS FUND WILL BE ADMINISTERED BY WGML THROUGH THE DISTRIBUTOR, AND WGML WILL SPECIFICALLY AUTHORIZE AND APPROVE ALL DISCOUNTS OFFERED IN THAT MARKET SECTOR.

SINCE WE ARE UTILIZING A PRICING STRUCTURE THAT IS SENSITIVE TO THE REQUIREMENTS OF EACH MARKET SECTOR, THE OVERALL COST OF GAS TO EACH DISTRIBUTOR WILL VARY SIGNIFICANTLY IN ACCORDANCE WITH THE NATURE OF HIS MARKET.

SLIDE F

"ESTIMATED IMPACT OF DISTRIBUTOR AGREEMENTS"

THIS GRAPH SHOWS THE ESTIMATED IMPACT OF THE FOUR DISTRIBUTOR AGREEMENTS ON THE ALBERTA BORDER PRICE OF GAS. THE SOLID RED LINE REPRESENTS THE ACTUAL BORDER PRICE FROM WGML'S CANADIAN SALES THROUGH TO THE END OF SEPTEMBER OF THIS YEAR. THE PINK COLOUR SHOWS THE ESTIMATED RANGE OF FUTURE PRICES ($2.15 - 2.30/GJ), OVER THE NEXT TWO YEARS. WE BELIEVE THAT EXPORT SALES WILL BRING OVERALL PRICES INTO THE HIGHER END OF THE RANGE.

THIS COMMENT ABOUT EXPORTS IS NOT A BAD LEAD IN TO OUR ACTIVITIES SOUTH OF THE BORDER.

SLIDE G
"WGML U.S. OBJECTIVES"

IN THE UNITED STATES OUR EFFORTS HAVE BEEN DIRECTED FIRST TO RETAIN OUR PROPORTIONATE SHARE OF OUR EXISTING U.S. CUSTOMERS' MARKETS - SECOND TO ENSURE THAT DISCRIMINATORY BARRIERS AGAINST CANADIAN GAS BEING ABLE TO ACCESS U.S. MARKETS WERE RESISTED AND - THIRD TO DIRECT OUR FUTURE MARKET FOCUS AWAY FROM THE INTERSTATE PIPELINES, WHO HAVE BEEN OUR TRADITIONAL CUSTOMERS, TO THE LOCAL DISTRIBUTION COMPANIES AND IN SOME INSTANCES INDUSTRIAL END-USERS.

SLIDE H
"LOGO"

THE RESULTS ARE MIXED. AS TO RETENTION OF MARKET SHARE WE HAVE ACHIEVED OUR OBJECTIVES WITH TWO OUT OF THREE OF OUR MAJOR CUSTOMERS, HOWEVER THEIR OVERALL MARKETS HAVE BEEN SIGNIFICANTLY ERODED BY SHORT TERM DIRECT PURCHASES BY LOCAL DISTRIBUTION COMPANIES AND INDUSTRIAL CUSTOMERS WITH THE CONSEQUENCE THAT OUR SALES TO THESE COMPANIES WILL BE LOWER IN 1985/86 THAN THEY WERE IN THE PREVIOUS YEAR.

AS TO MARKET BARRIERS - WE HAVE AND WILL CONTINUE TO RESIST INITIATIVES BY U.S. COMPANIES THAT PLACE CANADIAN GAS AT A COMPETITIVE DISADVANTAGE WITH U.S. PRODUCED GAS. WE HAVE BEEN SUCCESSFUL WITH ONE PIPELINE COMPANY AND WE ARE CONTINUING OUR EFFORTS WITH OTHERS, BOTH PRIVATELY AND WHEN NECESSARY IN THE REGULATORY ARENA.

OUR MARKETING STRATEGY CHANGE TO FOCUS ON LOCAL DISTRIBUTION COMPANIES RATHER THAN THE INTERSTATE COMPANIES IS YIELDING POSITIVE RESULTS. LONG TERM SALES AGREEMENTS APPROACHING SOME 400 MMCF/D HAVE BEEN EXECUTED SINCE WGML STARTED OPERATIONS ON JANUARY 1ST. INITIAL SALES UNDER SOME AGREEMENTS WILL COMMENCE IN 1987 WITH THE BULK OF GAS FLOWING BY NOVEMBER OF 1988. ADDITIONAL CONTRACTS ARE NEARING FINALIZATION.

"LOGO"

WGML'S EXPANDED EFFORTS TO COMPETE IN THESE MARKETPLACES HAVE MET WITH COMPETITIVE REACTION AND HAVE FURTHER OPENED OUR EYES TO THE SIGNIFICANCE OF REGULATION AND REGULATORY CHANGE.

NOW, LET ME NOW TAKE A STEP BACK TO REVIEW THE ENVIRONMENT OF REGULATORY CHANGE IN WHICH ALL OF THIS HAS OCCURRED. FROM WGML'S POINT OF VIEW AS A GAS EXPORTER, THE RECENT DEVELOPMENTS IN THREE

PRINCIPAL REGULATORY AND POLITICAL ARENAS (EDMONTON, OTTAWA, AND WASHINGTON) INDIVIDUALLY WARRANT MORE THAN THE 20 MINUTES I HAD BEEN ALLOTTED TO COVER THEM ALL.

SLIDE I

"REVIEW OF MAJOR DEVELOPMENTS"

IN THE INTERESTS OF STAYING WITHIN THE FEW MINUTES I NOW HAVE LEFT, MY FOCUS WILL NARROW TO REVIEW DEVELOPMENTS IN THE PROVINCIAL REMOVAL AND FEDERAL SURPLUS AND EXPORT FLOOR PRICE TESTS, AND SOME U.S. DEREGULATION EFFORTS. AS I REVIEW THESE ISSUES, THEIR IMPACT ON CROSS BORDER TRADE SHOULD BECOME APPARENT.

SLIDE J

"NEW ALBERTA PROTECTION FORMULA"

IN THE ALBERTA REGULATORY ARENA, THE ENERGY RESOURCES CONSERVATION BOARD HAS CALLED FOR A REVIEW OF ALBERTA'S REMOVAL TEST PROCEDURES. THIS HEARING IS NOW SCHEDULED TO TAKE PLACE THIS FALL. THE EXISTING TEST IS SIMILAR TO THE OLD AND HIGHLY RESTRICTIVE NEB SURPLUS TEST.

SLIDE K

"NEB SURPLUS TEST"

TURNING TO THE CANADIAN FEDERAL SCENE, AFTER PUBLIC HEARING, THE NATIONAL ENERGY BOARD IN MAY OF THIS YEAR ISSUED ITS DECISION ON A NEW SURPLUS TEST THAT WILL GOVERN THE AVAILABILITY OF NATURAL GAS FOR EXPORT. THE BOARD DECISION INTRODUCED A REVISED TEST THAT WHILE LESS ONEROUS THAN THE PREVIOUS TEST, APPEARS TO INTRODUCE A SIGNIFICANT NUMBER OF SUBJECTIVE ELEMENTS. THIS ASPECT HAS BEEN CRITICIZED BY A NUMBER OF PROMINANT PRODUCING INDUSTRY SPOKESMEN.

SOME INTERVENORS RECOMMENDED AT THE HEARING THAT THE BOARD DISPENSE COMPLETELY WITH A SURPLUS TEST AND RELY SOLELY ON CONTRACTS. THE BOARD'S ABILITY TO COMPLY IN THIS AREA WAS LIMITED DUE TO SECTION 83 OF THE NEB ACT. HOWEVER, WE BELIEVE THE BOARD, IN MODIFYING THE PRIOR SURPLUS TEST, HAS TAKEN A MAJOR FIRST STEP TOWARDS ELIMINATING UNWARRANTED BARRIERS TO FUTURE EXPORTS.

SLIDE K1

"NEB SURPLUS TEST"

IT'S OUR VIEW THAT THE BOARD IS BEING UNTIMELY AND PERHAPS UNFAIRLY CRITICIZED FOR THE SURPLUS TEST DECISION BECAUSE, SINCE

THE DECISION WAS ISSUED, THE BOARD HAS NOT BEEN CALLED UPON TO APPLY THE FLEXIBLE CRITERIA THAT THE NEW TEST CONTEMPLATES.

SLIDE L
"DEREGULATION IMPACT"

FOR EXAMPLE, CANADIAN DEREGULATION HAS OPENED UP OVER ½ OF THE MARKET TO RELIANCE ON AND DETERMINATION OF SUPPLY BY PRIVATE CONTRACTS, WHERE BOTH PARTIES CAN AND ARE AGREEING ON THE CONTRACT TERM. OBVIOUSLY, WHEN THE NEB COMES TO SET RESERVES ASIDE FOR THIS SEGMENT OF THE MARKET IT WILL HAVE TO DECIDE HOW MUCH WEIGHT TO GIVE PRIVATE CONTRACTS. I WOULD PERSONNALY BE SURPRISED IF THEY DIDN'T RESTRICT PROTECTION TO THE VOLUMES UNDER THE DURATION OF ESTABLISHED CONTRACTS. THIS TO MY MIND WOULD BE AN EXAMPLE OF THE BENEFITS OF THE "FLEXIBILITY" INHERENT TO THE NEW TEST.

SLIDE M
"SURPLUS TESTS"

CLEARY, A LONG PROTECTION PERIOD IS DESIRABLE AND NECESSARY FOR THE RESIDENTIAL AND COMMERCIAL USERS OF GAS BECAUSE THEY MUST RELY ON THIRD PARTIES FOR THIS PROTECTION AS THEY ARE NOT IN A POSITION TO CONTRACT FOR THEIR OWN SPECIFIC NEEDS.

It is important that clear and proper signals be communicated both ways between consumers and producers. It can be reasonably argued that if natural gas supply is kept artificially abundant due to an over-protective surplus test the price of gas would fall, in a competitive Canadian marketplace.

As industrial gas users perceive supply tightening they may seek and secure longer term contracts or arrange alternate energy sources. To expect producers to forego a certain sale and new markets in order to hold as inventory reserves that are not contracted for and may not even be needed (or wanted) by a Canadian end user in the future is unacceptable and profoundly bad economics.

SLIDE N
"EXPORT PRICE TEST"

The other potential impediment on furthering exports of Canadian gas is the export floor price test. Under the competitive conditions that now characterize the gas business in North America the export floor price has lost a great deal of its relevance. Effective competition in Canada ensures that adequate price signals will be sent from the consumer to the producer, and gas will have to be appropriately priced in order to compete. The NEB has recognized this shift through readjustment of the

PRICE TEST CRITERIA TO REFLECT CHANGED CIRCUMSTANCES BROUGHT ABOUT BY NORTH AMERICAN DEREGULATION AND SUPPLY/DEMAND IMBALANCES.

SLIDE O

"LOGO"

HOWEVER, WE BELIEVE, THAT NOTWITHSTANDING THE NEB'S DEMONSTRATED AND LIKELY FLEXIBILITY IN A NUMBER OF THESE AREAS, THAT BOTH THE EXPORT SURPLUS TEST AND EXPORT PRICE MATTERS SHOULD CONTINUE TO BE REVISITED AT THE POLITICAL LEVEL. SELECT GROUPS OF SENIOR MEMBERS OF THE CANADIAN GAS INDUSTRY SHOULD CONTINUE TO REVIEW WITH THE MINISTER OF ENERGY, MINES & RESOURCES AND THE NEB AND THEIR OFFICIALS THESE POTENTIAL IMPEDIMENTS TO THE ORDERLY MARKETING OF CANADIAN GAS.

SLIDE P

"U.S. REGULATORY ISSUES"

FINALLY, THE FERC ORDERS. A SERIES OF REGULATORY CHANGES IN THE UNITED STATES HAVE BEEN INTRODUCED, IMPACTING SIGNIFICANTLY ON

OUR BUSINESS. I INTEND TO DEAL BRIEFLY WITH THE FERC ISSUES AS YOU SEE THEM HERE 380, 436, 451, AND A PROPOSED REVIEW OF PURCHASE GAS ADJUSTMENT POLICY.

SLIDE Q

"FERC ORDER 380"

FERC ORDER 380 ESSENTIALLY ELIMINATES VARIABLE COSTS FROM THE MINIMUM COMMODITY BILLS. THIS FREED U.S. PIPELINES TO RENEGOTIATE THEIR GAS SUPPLY PRICES TO REMAIN COMPETITIVE AND REDUCED THE AVERAGE COSTS OF GAS. EVEN THOUGH 380 IMPROVED THE ABILITY OF U.S. PIPELINES TO SWITCH THEIR SOURCE OF SUPPLY AND REDUCE THEIR AVERAGE COSTS OF GAS, IT HAS ALSO MADE TAKE OR PAY PROBLEMS OF U.S. PIPELINE COMPANIES MORE SIGNIFICANT IN THEIR SUPPLY PURCHASE DECISIONS. I SHOULDN'T NEED TO PAINT ANY CLEARER THE NEGATIVE IMPACT THAT 380 HAS HAD ON CANADIAN BORDER PRICED NATURAL GAS.

SLIDE R

"FERC ORDER 436"

ON A MORE POSITIVE NOTE, THE ELEMENTS OF ORDER 436 HIGHLIGHTED HERE COULD GIVE CANADIAN GAS ACCESS TO MARKETS THROUGH THE UNITED STATES IF FULLY IMPLEMENTED. AS PIPELINES ARE ABLE TO WORK THEMSELVES OUT OF TAKE-OR-PAY SITUATIONS, CANADIAN GAS CAN BE

MORE ATTRACTIVE. EXPEDITED CERTIFICATES FOR FACILITIES HAVE ALLOWED TCPL INITIATIVES SUCH AS THE IROQUOIS GAS TRANSMISSION SYSTEM TO MAKE A STRONG BID FOR SERVICE INTO GROWING U.S. MARKETS.

BLOCK BILLING COULD HURT OUR MARKETING EFFORTS BY ROLLING CANADIAN GAS IN WITH HIGH PRICED BLOCK 2 GAS. FORTUNATELY IMPLEMENTATION OF THIS PART OF 436 HAS BEEN DELAYED (AND COULD BE DROPPED ALTOGETHER).

NOT ALL IS ROSY WITH 436. AS PIPELINES RE-ALIGN THEIR RATE STRUCTURES THERE IS SOME POTENTIAL FOR DISCRIMINATION AGAINST CANADIAN GAS. AS WELL WE HAVE OBSERVED THAT PIPELINES CONNECTED TO THE U.S./CANADIAN BORDER HAVE BEEN SLOW TO FILE FOR OPEN ACCESS UNDER 436.

SLIDE S
"FERC ORDER 451"

ORDER 451 IS FERC'S ATTEMPT TO CIRCUMVENT SOME OF THE MORE ONEROUS ELEMENTS OF PRICE CONTROL LEGISLATION IN THE U.S. THE IMPACT OF 451 WILL NOT BE MEASUREABLE UNTIL AFTER NOVEMBER 1, SINCE THAT IS WHEN THE ORDER ACTUALLY COMES INTO FORCE. HOWEVER, I THINK I CAN SAFELY SPECULATE ON ITS IMPACT IN THE MARKETPLACE. FIRST OF ALL, ACTIONS TAKEN UNDER ORDER 451 TO RAISE OLD GAS PRICES WILL NOT LIKELY CHANGE AVERAGE PRICES IN THE MARKETPLACE.

PRICES ARE BEING SET BY INTER- AND INTRAFUEL COMPETITION AND NOT BY THE COST OF SUPPLY. SECOND, IF OLD GAS IS ABLE TO COMMAND A HIGHER PRICE, THEN, IN THE LONG RUN IT IS MOST LIKELY THAT, MORE LOW COST U.S. RESERVES WILL BE AVAILABLE TO U.S. MARKETS.

THERE IS LIKELY TO BE LITTLE OR NO SHORT-RUN IMPACT ON CANADIAN GAS SALES TO THE U.S. BUT IN THE LONG-RUN GREATER LOW-COST GAS SUPPLIES COULD MEAN GREATER COMPETITION TO CANADIAN SALES.

SLIDE T
"REVIEW OF PGA"

FERC HAS ANNOUNCED ITS INTENTION TO REVIEW ITS PURCHASE GAS ADJUSTMENT POLICY, PROMPTED BY THE NEED OF PIPELINES TO LOWER GAS COSTS QUICKLY TO REMAIN COMPETITIVE. THIS REVIEW AND FLEXIBILITY IS LIKELY TO BE ADMINISTERED ON A CASE-BY-CASE BASIS FOR ALL INTERESTED PIPELINES (INCLUDING THOSE TRANSPORTING CANADIAN GAS). AN INCREASE IN COMPETITION BETWEEN INTERSTATE PIPELINES AND AN INCREASE IN THEIR ABILITY TO COMPETE WITH ALTERNATIVE FUELS IS ANTICIPATED.

"LOGO"

WHAT DOES ALL OF THIS MEAN TO CROSS-BORDER NATURAL GAS TRADE?

GOVERNMENTS AND REGULATORY AGENCIES IN BOTH CANADA AND THE U.S. ARE COMMITTED TO DEREGULATION OF THE NATURAL GAS INDUSTRY. THE OVERALL INTENT OF DEREGULATION IS TO MAKE IT SIMPLER FOR A WILLING BUYER AND SELLER OF NATURAL GAS TO CONSUMATE A BUY-SELL AGREEMENT, WITH BOTH PARTIES FULLY EXPOSED AND RESPONDING TO COMPETITIVE MARKETING FORCES. WE IN WGML SUPPORT AND APPLAUD THESE DEREGULATION EFFORTS.

BUT, TO DEREGULATE, GOVERNMENTS AND REGULATORY AGENCIES IN BOTH COUNTRIES HAVE HAD TO INTRODUCE A WHOLE NEW LAYER OF GOVERNMENT POLICY AND AGENCY REGULATION. MUCH OF THIS NEW POLICY AND REGULATION IS UNTESTED. MODIFICATIONS WILL BE REQUIRED. IT IS IMPORTANT THAT WE ALL REMAIN FLEXIBLE TO ACCOMMODATING THESE MODIFICATIONS OVER THE NEAR TERM.